COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                 )
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Informational Proceeding and      )
Preparation of the 2004 Integrated) Docket No.
Energy Policy Report (IEPR) Update) 03-IEP-01
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Re: 2004 Transmission Update      )
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

MONDAY, JUNE 14, 2004

9:35 A.M.

Reported by:
Peter Petty
Contract No. 150-01-005

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Ann Jones

Mike Smith

STAFF and CONTRACTORS PRESENT

Kristy Chew

Don Kondoleon

Judy Grau

Sandra Fromm

Mark Hesters

Susan V. Lee
Aspen Environmental Group

Joe Eto
Lawrence Berkeley National Laboratory
Consortium for Electric Reliability Technology Solutions

ALSO PRESENT

Armando Perez
California Independent System Operator

Barbara Hale
California Public Utilities Commission

Ed Smeloff
San Francisco Public Utilities Commission

Greg Karras
Communities for a Better Environment

ALSO PRESENT

Anjali Sheffrin
California Independent System Operator

Mingxia Zhang
California Independent System Operator

Roland Schoettle
Optimal Technology, Inc.

David Olsen
Center for Energy Efficiency and Renewable Technologies

Steven Kelly
Independent Energy Producers Association

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Los Angeles Department of Water and Power

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Chifong Thomas
Pacific Gas and Electric Company

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Transmission Agency of Northern California

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San Diego Gas and Electric Company
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Patricia Arons
Southern California Edison Company

Chuck Gilfoy
TransAlta

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P R O C E E D I N G S

9:35 a.m.

PRESIDING MEMBER GEESMAN: I'm John Geesman, the Commission's Presiding Member for its Integrated Energy Policy Report. This is the 2004 update process.

To my immediate left is Commissioner Boyd, who is the Associate Member of the Integrated Energy Policy Report Committee and the formerly Presiding Member of the 2003 report Committee. And to my right is my Staff Advisor, Melissa Jones.

I have a fairly lengthy opening statement that I want to make because the staff has spent a fair amount of time trying to lay a context for today's workshop. So, if you'll bear with me I'll take us through that.

Today's workshop is the fourth event of the 2004 transmission update process. The purpose of the transmission effort in 2004 is to take action to implement the 2003 Integrated Energy Policy Report's goals. The 2003 IEPR brought forward the importance of modernizing and upgrading the bulk transmission grid; and identified both planning and permitting actions that the state should take to improve the system in a cost effective, environmentally sensitive manner that insures a reliable, robust system.

The first event in our update process was the November 6, 2003 Committee workshop to identify key transmission planning issues, including how best to capture the strategic benefits of transmission assets.

The second event was the April 5, 2004 Committee workshop that had three objectives. One, to discuss long-range transmission system interconnection needs under various scenarios. Two, to begin stakeholder-driven development of a state long-run transmission system vision. And three, to understand the transmission problems of immediate concern, the critical short-range projects to address these concerns, and the consequences of delay in bringing them online.

The third event was the May 10, 2004 Committee workshop. That workshop examined the general topic of renewable resource development and transmission constraints in southern California; and the particular question of how wind resources in the Tehachapi region and geothermal resources in the Salton Sea region should be interconnected to the grid.

It also described the Commission Staff's proposal for a southern California transmission corridor study; and sought feedback from interested parties on its content, value and timing.

Finally, it continued the discussion of the development of a long-term vision for California's transmission system.

At today's workshop we will examine how alternatives to transmission expansion have been considered up to this point along the planning and permitting spectrum, and seek input from panelists and interested parties on how, where and when alternatives should be assessed in the future.

We will also hear from the Cal-ISO and CERTS, the Consortium for Electric Reliability Technology Solutions, on methods for valuing the strategic benefits of transmission interconnection.

We will also receive updates from Commission Staff on its continuing efforts to define and develop a transmission corridor study and a long-term transmission vision.

The staff will publish its draft

transmission white paper at the end of July. The Committee will then hold workshops and/or hearings on the white paper in mid August. The Committee will then publish its final transmission report in late September. That will ultimately come before the full Commission as a part of our 2004 update by the end of October. I believe the deadline that we are shooting for there is November 1.

Kristy, should we go ahead, then?

MS. CHEW: Yes, thank you. Good morning, everyone. My name's Kristy Chew. I'm a Project Manager here at the Energy Commission. I'd just like to take care of a few housekeeping items before we get started.

For those of you who are not familiar with our building our restrooms are right behind the opaque partition, and there's a water fountain there, as well. There's a snack bar up on the second floor for drinks and snacks and sandwiches and stuff if you're interested.

And the workshop agenda, the finalized one, and handouts for the morning session presentations are on the back table as you enter the room. I know that we are out of some copies already, and they're being made right now. So, if there's a presentation that comes up and you don't have a handout, go ahead and check the back table; we've probably made more and brought them in already.

There's also a workshop sign-in sheet, so if you could sign in and let us know that you came and who you are representing; that would be very helpful.

And this meeting is also being transcribed. The court reporter right there, waving his hand. If you could make sure that you state your name, and if you have a business card if you'd give it to the court reporter so he can get the proper spelling of your name and your organization, that would be helpful, as well.

Because it's being transcribed if at any time you can't hear what's being said, if you could please raise your hand and let us know, because if you can't hear it, then there's a chance that the court reporter isn't picking it up, either. So, for everyone's benefit, if you can't hear it, let us know.

And lastly I'd like to introduce some of the other Energy Commission Staff that are here today. Don Kondoleon is right up here; you probably already know him. And Sandra Fromm and Mark Hesters are in the back, also working on the IEPR. And Judy Grau is making a presentation this afternoon, although she is out this morning for a doctor's appointment, but she'll be here this afternoon.

So I think that covers just about all the housekeeping items. If there's any type of problem, need more handouts or something, water, just let me know. Raise your hand I'll come find you. Okay. Thanks, bye.

MR. KONDOLEON: Good morning and welcome to the Energy Commission. My name, again, is Don Kondoleon; I'm the Commission's Transmission Program Manager.

To begin this morning session we will have a presentation by Susan Lee of Aspen Environmental Group to talk about a report that they've done for us entitled, Comparative Study of Transmission Alternatives. So please welcome Susan Lee.

MS. LEE: Thanks, Kristy, and thank you, Don. Again, I'm Susan Lee with Aspen Environmental Group. Before I start I want to tell you a little about my experience because that sort of sets the stage for my interest in this topic, as well.

My expertise is in the CEQA side of transmission alternatives. I've managed many of the recent transmission line projects for the California Public Utilities Commission, including the Jefferson Martin Project, Path 15, TriValley and North of San Jose. And also for the Energy Commission over the past few years I've written the staff assessment alternatives analyses for several of the power plant projects, including Potrero Unit 7, Morro Bay and East Altamont.

In each of these reports in the CEQA analysis we've looked at both transmission alternatives and nontransmission alternatives, which were so-called nonwires alternatives. Including things like renewable energy and distributed generation.

But because the analysis that we do in the CEQA process happens relatively late in the game, and we'll show that in a kind of timeline in a little bit, it's hard for us to look openly at that wide range of alternatives because we're restricted by the CEQA requirements for how we look at alternatives. And I'll explain that also in a little bit.

So, it's been sort of frustrating to me over the past five or six years in the transmission process to see that it's difficult on the CEQA side only really to look at a wide range of alternatives. And to me that's why this process is so important, to broaden the consideration of alternatives, move the consideration really earlier in the process.

The other things that I'm sure a lot of you have seen in the past few years is that transmission projects are coming up against much more strong opposition, especially when they get into developed areas or up near developed areas, which makes the consideration of alternatives really much more important.

Let me give a quick overview of the presentation I'm going to give today. First I'll go over the purpose of the study, and Commissioner Geesman covered that a little bit already. Then I'll describe what the alternatives are to transmission just briefly.

I'll describe a couple of examples of nonwires alternatives to transmission, things that have been considered or tried to have been considered in the past. And then we'll focus on a couple of questions that really set the stage for what we're hoping to hear from the rest of you over this afternoon, of the rest of this morning, which is where in the process can we better consider alternatives, and what methodology can we use in that.

And just a reminder, again, because the talk I'm giving this morning is fairly brief, there's a lot more information in the background report; and there were copies, I think they're still out there at the front table, that goes into a lot of this in more detail.

There's an appendix to that report, as well, that covers a description of a lot of the ongoing proceedings. As you know right now there are proceedings ongoing at the Energy Commission, the CPUC and the ISO talking about a wide range of issues that all relate to this. So some of those are covered in that appendix and that should be helpful.

Okay, why are we here this morning. Commissioner Geesman covered a lot of this in his introduction, but let me just run through it. As you know, California's growing. We need more energy; we need energy sometimes in different places than we thought we needed it a few years ago.

The main thing that's become clear to us is that the planning process, which is managed essentially by the ISO and the utilities, and then the permitting process that happens at the CPUC are not directly connected. Each of those processes has a stage to look at alternatives. But because they happen sequentially, first planning then permitting, the timelines are difficult. It stretches the process out over quite a bit of time.

So, we're hoping that we can, through this discussion, try and come up with a method where the process can be streamlined. The third bullet on here points out one of the things that makes this especially good timing right now. Because there are ongoing proceedings, as I mentioned, at each of these different agencies, it's a very good time to be looking at change.

There are proceedings that are looking at, for example, the CPUC's procurement proceeding. We have proceedings on distributed generation, renewable energy. All of these things come together when we're looking at transmission alternatives.

The last thing on this slide is the issue of timing. And I mentioned earlier that because on the CEQA side we see the timing as really an obstacle to being able to consider many alternatives because we're usually to that point only a year or two away from when the project is urgently needed. It restricts the evaluation of alternatives. It would be much easier and more efficient if a wider range of alternatives could be considered earlier on in the process.

So, just briefly, the methodology that we're looking at, and this, again, mirrors what Commissioner Geesman mentioned this morning, we're really looking at this as a process. We don't have a product right now. What we're hoping for is that we'll get input from a wide range of stakeholders, and I know there are a lot of people here today who have some really good input for us. We hope that the input will let us come up with a draft methodology that we can then present back to you. And get another round of feedback.

One of the biggest challenges obviously

here is that transmission line projects fall under a wide range of jurisdictions. A lot of different agencies are involved. And when you get into nontransmission alternatives, we're looking at even another set of agencies, because a lot of times those alternatives require approval only at the local level.

So, acknowledging those jurisdictional challenges and regulatory challenges we want to move into the consideration of alternatives and see what we can work out.

Just as a very basic general background, in order to look at alternatives we need to look at what the purposes are for a transmission line. The obvious one is to move electricity from one place to another. There are other less obvious purposes. Sometimes a transmission line is proposed only to improve reliability; sometimes to reduce transmission congestion; and sometimes to reduce costs when you're trying to move, say, from generation to load.

The challenges of transmission line siting, and again I mentioned earlier that this is becoming more and more difficult with time, is one of the most important reasons that we need to look at alternatives. California's growing. We're seeing residential growth in areas that previously hadn't had growth. As growth occurs, the growth, itself, becomes a barrier to transmission lines because the places that ten years ago we would have though would have been a perfect transmission corridor all of a sudden is now a new city that wasn't there.

So the land for the corridors is disappearing as new homes are built. Transmission lines that are proposed through developed areas are meeting much more well-organized opposition. I think people are learning about the process. They're understanding what it takes and how much more beneficial it is to have a well-organized opposition coming, for example, to the CPUC and working through that process.

The kinds of issues that are generally raised up in transmission projects, really the biggest three issues, and these are probably the most challenging issues because they are the most subjective, are visual impacts, property values and electric and magnetic field concerns. Those are the things that when people come to a CEQA scoping hearing that they generally point out as being the biggest concerns to them.

Other environmental effects always come up on a project-by-project basis. For example, biological resources, cultural resources, you know, construction emissions and air quality issues.

Okay, so what are the alternatives to transmission lines. We have in the background report there are probably 20 or 30 pages that talk about this, so I'm just going to go into a kind of very brief overview on this.

Because, again, the purpose of a transmission line essentially is to carry power from one place to another, the simplest alternative is to generate power at the end of the line, the place where the power is needed.

The first three things shown on this slide really are generation alternatives. The fossil fueled power plants are pretty efficient. They can be located ideally wherever there is natural gas and water. But even at the peaker level, the single turbine kind of smallest fossil fuel generation option, there's generally fairly significant opposition from local people if it's a developed area. Which, again, is where you tend to need the power to be located. Again, those impacts can be visual resources, noise and air emissions.

Distributed generation includes a large range of technologies which again are kind of small scale, things like fuel cells and photovoltaics. These things, again, are directly beneficial because the power's produced at the location where the need actually occurs.

These technologies are improving and their costs are going down. So, distributed generation optimistically is going to be a part of our future.

Renewable energy, this is a huge broad topic and there are, you know, many people in this building that are studying this. It includes obviously wind power, geothermal, biomass, solar and tidal power. These technologies each can generate a large amount of power really equivalent to a fossil fuel plant if they're located in the right place.

The challenge with many renewable technologies is that they are geographically depending. That, you know, for example, wind and geothermal in particular, you have to build the plant or the generation facility at the location where the resource occurs.

Economic incentives also relate to power plant needs -- excuse me, to transmission line needs. In many cases transmission lines are proposed specifically for economic benefits to offset the costs of reliability must-run plants or congestion fees.

Demand management, I've got another slide on that. Demand management is also really important and increasingly important in the energy field because transmission lines are designed to carry power that serves the peak load. And those peak loads occur at a small number of hours over a year. If you can reduce demand just over the peak period you get much greater flexibility in terms of how you meet your energy needs.

Technology has been pretty successful in allowing consumers, both residential and industrial, to change their energy use patterns. And we think that's something that will improve, and I'll give you some examples of that in a little bit.

You know, conservation can be very effective. It was in 2001 when energy was in the news pretty much every day. The state's energy demand dropped really dramatically because consumers responded to the need to save power. But within about six months after that, as energy stopped being in the news, people pretty much went back to their old habits. But we know that it's a possibility to get people to conserve really with significant savings.

Another demand management option is load shedding. This is something that can happen on either a voluntary basis, if a large consumer opts to basically not receive power in areas in times of especially high demand, and they get a benefit to that from lower rates. Or it can be on a mandatory basis which we all experienced a couple years ago with the rolling blackouts. Not an ideal situation.

Load shifting is another area that I'll talk about in a little more detail. But it's a place where users can reduce peak demand by using electricity during nonpeak hours instead of peak hours. You know, the simple example is running your dishwasher in the evening instead of the afternoon. And we'll talk about examples of all of these things in just a little bit.

So, just in conclusion to kind of wrap up what the alternatives to transmission are, we have obviously gas-fired power plants. They're a good solution if the impacts are not a problem. But they're best used as alternatives to transmission if they're located where demand is. And, again, that's the biggest challenge because that's where they're hardest to site.

Renewable technologies are improving in terms of technology; and costs are dropping. But, again, some of those have to be located where the resources are, that the two biggest potential producers, wind and geothermal, are the most geographically constrained. The disadvantage there, of course, is you need additional transmission lines to get that power to the load.

The other small scale options, and these include the variety of distributed generation options, economic incentives and demand management issues. All of these can be looked at as components of a portfolio, or of ways to determine to defer transmission need for a year or two. This is something the City of San Francisco has been really focused on. We're going to hear about that in a little bit.

This slide shows a very generalized timeline of how the process works now. And it has to be generalized, every project is a little different. But, the basic idea is that in the first year between year zero and year one the problem, itself, is identified. What is the problem we're trying to solve.

And years one and two, there are discussions, this is generally again with the ISO and the utility, of how different ways the problem can be solved. Alternatives are looked at at that point in terms of generally it focuses only on transmission alternatives. And this is the point, I think, that we need to most focus on as we move into this process.

The other time that alternatives are considered, and this is the time that I've most been involved in, is essentially at step five, which is in years three and four. At the CPUC's process, CPCN here, this is the certificate of public convenience and necessity, which is the application that the IOUs file with the CPUC.

At this point we are within a year or two of the project being essentially most needed, if it is a very urgent process. So when we look through the CEQA process, which I'll describe, we have many fewer options at this point.

Let me just take that timeline and superimpose on it a real project. This is an example that is current right now because the draft decision is actually out as of last week.

Jefferson-Martin started, the concept really started in the end of 1998 when we had the San Francisco blackout, reinforcing the idea, which transmission planners were certainly all aware of, which is that the San Mateo substation was basically the only source of power going into the San Francisco Peninsula.

So the concept was developed that we really needed to create a separate path for electricity getting into the San Francisco Peninsula; and the Jefferson substation became the focus of that.

So, in 1999 and 2000 the ISO and a group of stakeholders and PG&E started meeting to develop what ultimately became the Jefferson-Martin project. A variety of alternatives were looked at, including a cross-Bay transmission line, other routes up the Peninsula. And even generation was considered at that point.

It took a year or so for that study to be finalized. Then after that PG&E started preparation of its CPCN. That includes the environmental material and the engineering material that goes into the CPUC. That was submitted to the CPUC in late 2002.

After the preparation of the draft and final environmental impact report that pretty much took all of 2003; the final EIR came out in November. Then the CPUC started their evidentiary hearings the first couple months of this year. And the draft decision came out just last week. The schedule at this point is that it could be voted on as early a the beginning of July.

So, to look at this was clearly a very urgent project from when it was first identified. And it took more than five years to get from the planning stage to the point where it may even be voted on. The construction, itself, will of course take at least another year, probably closer to two years once it finally gets going.

Let me put in context what we do in the CEQA process, just so you can understand. I know a lot of folks here are more into transmission planning and don't see as much what happens later on. But this is part of the challenge that we see on the CEQA side of how we can evaluate these things successfully.

The CEQA guidelines present very specific requirements for how we look at alternatives. And there are three things that they require us to look at. The guidelines require us to evaluate only alternatives that meet most of the project objectives. And these are the objectives that are defined by the developer, itself.

The challenge we most often face here, and I've pointed that out a couple times, is the timeframe. If one of the objectives is a project has to be online by 2006, and we are in a process already in the beginning of 2004, they're automatically screening out a variety of alternatives that might take longer than that to be implemented. And that can happen because of technology or because of regulatory barriers. So that's one of the challenges we face in CEQA.

The second requirement is feasibility. Alternatives must be feasible. This means economic feasibility, environmental, social, regulatory. The thing that comes up often in this context is regulatory feasibility. Could it really be permitted, or is there some way to actually make this alternative happen, given the regulatory structure. So that's a challenge that we deal with quite a bit.

And then the third one, which is the environmental side, is that an alternative must have the potential to reduce or avoid the significant effects of the project, itself. So at the very beginning of a project we have to screen it to see what the potential significant effects are, whether there's a way to eliminate one or any of these one or multiple significant effects by looking at an alternative.

But if there's an alternative, for example, that has greater effects than the proposed project, that's an alternative that we can't, under CEQA, look at.

And, again, let me take the Jefferson-Martin example and show you what we did to look at alternatives here. In Jefferson-Martin in the environmental impact report we ended up looking at -- in CEQA you end up with two categories of alternatives. Alternatives that are fully analyzed in detail in every issue area; and then alternatives that are eliminated. And you document this, which ones we tried to evaluate or we considered but were eliminated based on those CEQA criteria that I defined.

So, under Jefferson-Martin, the fully analyzed alternatives that we looked at were only route options. And we looked at a wide number of overhead route options, underground route options, and different locations for the transition station that transitions between overhead and underground. Those kind of alternatives are generally driven by land use concerns.

The alternatives that we eliminated in this case, and this has been consistent with pretty much all of the CEQA projects we've worked on, were all the nonwires alternatives. Things like new generation, and we looked at Potrero Unit 7 and we looked at the turbines that have now since then, of course, been submitted in AFC to the Commission here.

We looked at renewable resources, system enhancement in terms of distributed generation and demand side management. And all of these things were eliminated because they couldn't meet one, or in some cases more than one, of those CEQA requirements that I listed. They either had more impacts that the proposed project. In some cases they required quite a bit too long of a timeframe. Or they had regulatory hurdles that made it seem very very unlikely that they ever could get permitted.

This is the beginning. I'm going to talk about a couple examples of real life, or almost real life, as in proposed, nonwires alternatives. The first one that came up in this area was the TriValley RFP. And this was a request for proposals that was issued by the ISO in January of 2000.

In the late 1990s the need was identified for additional electricity, one way or another, transmission or generation, in the TriValley area, which is San Francisco's East Bay where Livermore, Pleasanton and Dublin are located.

PG&E proposed a transmission solution, the TriValley 2002 capacity increase project, that would have brought, in fact did bring, 230 kV power into the TriValley area, and included the building of two new substations.

At about the same time the ISO issued an

RFP for peaking power. This RFP would have solved essentially the same problem. Had the RFP been successful and peaking power been constructed in the TriValley area, the 230 kV could have been at least deferred for quite a bit of time, or maybe put off entirely depending on how the transmission system had been reconfigured.

But the conclusion was -- the ISO got four responses, the conclusion was that the alternatives were not as cost effective as transmission. So PG&E went ahead with the transmission line proposal. We prepared the EIR. It was approved by the CPUC. And, in fact, the TriValley project is, two phases of it are operational right now, and the third phase is just starting construction.

One of the really most interesting nonwires discussions that's going on right now is with BPA. This is the Bonneville Power Administration of the Department of Energy, again in the Pacific Northwest.

BPA formed a nonwires roundtable in 2003 and they're doing a great job at documenting what they're doing on the internet. So we put the websites on here for just their standard update, and also for their newsletter. They had a newsletter that just came out last month talking about nonwire solutions.

The purpose of BPA's nonwire solution, it's very similar to what, I think, we're trying to do here. The general idea is they want to fully consider nonconstruction, as in nontransmission alternatives, before they get into transmission planning. So the idea is to move the consideration of these alternatives up front so that before you get into detailed transmission planning you've really fully considered what the alternatives are.

BPA's got four pilot programs that they've described. In fact, these descriptions are from that May newsletter that was on the link a couple slides ago. The first project is a voluntary load reduction pilot that works with both industrial and commercial consumers, allowing them to use the internet on an internet-based platform where the prices, electricity prices are actually posted hourly.

They did a pilot on that program that was, I think it was four days long, earlier this year. And it was very successful, in their minds;

just in that short timeframe they found that users voluntarily opted to reduce load when prices were high. And they dropped load by 22 megawatts, which in the area they're looking at, this was in the Olympic Peninsula, was equivalent to one full year's load growth.

Another pilot they're looking at is one called direct load control. And this is basically a load-shifting project where they're trying to educate both residential and commercial consumers to shift their load from peak periods to nonpeak periods. And, again, with a price incentive on both parts.

The last two BPA projects are both distributed generation based, or at least include distributed generation as a component of each of these pilot projects.

The first one would provide day-ahead notice when they're into a very high peak period where it's clear that the following day is going to be a problem in terms of serving load. And requires certain users, who have been previously identified, to switch to distributed generation that they have onsite on an emergency basis.

The next BPA option that they're looking at is a combination of load reduction and a distributed generation pilot. This is another experimental situation and BPA actually is just looking for volunteers to participate in a test program for this one at this point.

But what they would do is actually allow BPA to control certain major building functions like air conditioning. And they're testing things like, you know, how long can you turn off air conditioning in a building before it becomes uncomfortable. And can that be done at peak. If they could do that for an hour or two everywhere at peak, obviously that could make a huge difference in an area where you have a lot of large buildings.

And then that's in combination with some onsite microturbines. And, again, giving BPA control with the users' consent.

One of the big things we want to hear from people today about, and I think this will be more the focus of the roundtable, is what have we learned from some of these processes that have gone before us.

The TriValley RFP was a really interesting attempt to shift from transmission to generation. We'd love to hear from people about what the problems were with that. Was there something that could have been changed in the ISO's process. Was the time an issue. What could have been done to make this project more successful.

One of the other things that I think a lot of people have different ideas on is what could have been done in the Valley to Rainbow project to make that project survive basically. I think there's the possibility that a different route had -- the utility looked, maybe, at some different route options. Obviously the route option that was selected in the proposal was highly controversial; resulted in a very very well organized public opposition campaign that really fought the need issue. But the need issue may not have become such a big issue had a route been chosen that was not perceived as being as offensive to the local folks.

So, the extent to which the opposition to this project resulted in its disapproval, we'd love to hear your thoughts on what could have been changed either in this project, would a different route have made a difference; what could have been changed in the process that might have let this project survive. And, you know, any other thoughts you would have as far as what might have made Valley to Rainbow succeed. Or whether, you know, there are nontransmission alternatives that could have solved the same process.

So now, in wrapping, we're coming back to the big questions that we'd love to get your input on during this morning. The first big question is where in the process do we consider nontransmission alternatives.

I talked about the fact that the early part of the process is focused on utilities and the ISO with stakeholder groups. The later part is the CEQA process. Does the existing process work. Is there some way we could change the existing process to wrap more nontransmission alternatives in that. Or do you have suggestions for a revised process that would better allow consideration of alternatives.

The next big question is the methodology. How can we come up with a methodology that lets us consider alternatives, nonwires alternatives, fairly against the transmission projects. And, again, because there are two stages that we look at alternatives right now, thoughts about the planning stage methodologies, what could be done in the very early stages to evaluate transmission against nontransmission. And is there anything we can do in the CEQA process, still staying within the CEQA guidelines, that would allow us to more openly consider nontransmission alternatives.

And this is my last slide, just kind of a summary of where we go from here. And again, mirroring the Commissioner's statement. We've got presentations this morning by several of the other major agencies, and also public stakeholders groups.

After this workshop you'll notice in the workshop announcement that there is, I think, until June 24th, a comment period for which we would love to get written input from people, followup if you have thoughts, in the next week or so about things that you've thought of after you hear the roundtable presentation and the other presentations this morning.

We're going to prepare a summary paper once we get all that input, and obviously the verbal input from today. If it's needed, we'll have another workshop. If we come up with a methodology that it seems logical that we would like to get, you know, another round of public feedback on, we'll do that.

And this whole process is coordinated with the 2004 and 2005 IEPR updates that are ongoing at the Commission.

That's it for my presentation. If anyone has questions we can do them now, or we can move on to the next speaker.

COMMISSIONER BOYD: I would like to ask you a question, or an observation. One of my concerns is -- I mean this is very comprehensive and I appreciate it. And this is a good process. And we're sitting here today just thinking about transmission lines, which is a very big topic.

But your list of challenges to transmission line siting just reminded me of the same challenges we face with regard to any infrastructure improvement we try to make. And I guess part of the problem is, in my mind, in my personal opinion, well, one, there's 36 million of us here now, not 16.

And number two, maybe some less than desirable land use planning decisions made down through the decades predicated on what I'm not quite sure. You could make a list of political pressures and need for local financing and et cetera.

But I just keep worrying about or wondering about the advisability of looking at corridors in a broader kind of way. That is public infrastructure corridors. I mean land, we're losing it very fast. The idea of delaying anything to some future point in time just aggravates the problem probably of there not being land, or "not in my backyard" or not in my visual.

And do you run into any people thinking about the broader question of public infrastructure, public utility corridors to meet needs for potential natural gas pipelines, even transportation projects, et cetera, et cetera.

I mean maybe I'm dreaming of a perfect world, but it would be good.

MS. LEE: It would be good, and unfortunately it's very little seen. The first place I've seen it happen, and I've been very glad to see it happen, is the corridor study that the Commission is doing right now.

Up until then the only place that we've

seen really comprehensive planning done is on federal lands. Because both national forests and the Bureau of Land Management, on big chunks of land, actually identify transmission corridors. They plan them consciously. They put them on their maps.

So, you know, if you're coming in with a transmission line or a pipeline you know that there is a place that you can go with those.

But, the really unfortunate thing, as California's been growing so fast, there hasn't been any planning. You know, some communities hardly plan even for residential development and just let it go where developers want it to go.

But, I agree that it's too late in some cases. But it's much better to get started now. I think anything we can do to identify corridors that remain, or do anything to identify places that we might be able to preserve as transmission corridors is really going to be important.

Because even, for example, with Valley to Rainbow, you know, the Valley to Rainbow project went through some areas that had been developed in only the past few years. But waiting even a year or two on that project, there's so much growth in those areas of, you know, Temecula, Riverside County, that you're basically losing corridor options almost every day.

So, it is an issue that I think we need to move on absolutely as soon as possible, because it's only going to get more difficult.

And, you know, a lot of people think transmission lines can be undergrounded and solve all the problems. Undergrounding works for a short periods of, you know, short lengths of space. You can do it to avoid an obstacle, to preserve a really great visual resource. But, you know, something on the scale of Valley to Rainbow or Tehachapi or Devers-PaloVerde, you can't underground on. There's no financial logic to that. So, it doesn't solve all the problems, even though a lot of people think it would be nice.

So, it is a big challenge, I agree.

Any other questions? Okay.

MR. KONDOLEON: Okay, thank you, Susan. I again want to remind folks that the copy of Aspen's report to the Commission is available at the desk at the entrance to the hearing room; or it can be accessed through our website.

The next phase of this morning's session will be a series of presentations provided by stakeholders on their perspective on alternatives. And the first of the presentations will be provided by my good friend, Armie Perez, from the California Independent System Operator.

MR. PEREZ: Good morning, everybody. Gary DeShazo was supposed to be making this presentation, and he had to fly to Portland for a meeting this morning, so I'm replacing him. It's usually the other way around, but he sends his regrets.

But I'm really happy to be here because this happens to be one of my favorite subjects in life, and I can talk about this until you guys get sick of me.

And let me start by asking you to pay attention to my title. When I first was hired at the California ISO back in 1997 my title was Director of Transmission Planning. Within three months the CEO was getting a memo from me says I have to change my title. You just told me that the only thing I can do to make the state healthy is to build transmission and I refuse to do that.

Transmission is not the only solution to the problem; in some cases it is not the best solution to the problem. So we changed it to Director of Grid Planning so people would be a little bit more wide in the interpretation of what that means.

One quick slide, usually like to give you the company level here, which is what do we do, the ISO. We maintain reliability of the control grid, and we measure that reliability against NERC, WECC and our own ISO standards. And we plan and expand the control grid to insure a reliable and efficient transmission grid. Notice that I switched words on you again.

Now, we have -- the next two items is something that also gets me into trouble, it has gotten me into trouble with the chairman of my own board. But let me try one more time. I try to say that a project is needed based on one of two reasons. Reliability, which means I broke the standards and I have to meet the standards, so I need to do something about it. Or economic; expansion is really the best thing that the ratepayers can do because they will pay less for the expansion than they would if they didn't make the expansion.

Some of the most simple economic

examples is eliminating congestion; or in some cases, as simple as trying to reduce the amount of losses on the circuit. And just, you know, make for better conductoring. We try to do our best to work proactively with all the stakeholders to achieve the best solutions for the system.

Now, what's in my tool box. I have a very detailed system representation of the California grid, plus a very detailed representation of the entire western system. That means I know where all the busses, all the transmissions lines are, all the loads, everything that you can think about. And I have it for the next 10, 15 years.

I also have a fairly detailed base of the economic information associated with generators in terms of the type of fuel they use; some guess about how efficient they are, and so on and so forth. Those two tools allow me to answer the question of whether I need something for either an economic reason or reliability reason.

Now, we're going to have to do a little bit of the same things that you heard from Susan, because she and I did not coordinate, but hopefully it will be a little different.

If I get into a problem or if I have a problem I can solve it by either adding transmission; I can add generation; I can look at demand side options; or a combination of all the above.

But if you look at the ISO's role at the moment only the first one is available to me. There's nothing I can do about generation; there's nothing I can do about the demand side efficiency, or combining the two. As a matter of fact every time I go downtown to the CPUC somebody's going to make the statement that the only solution for a transmission planner is transmission. At this point in time they're absolutely right and I hate that statement. And I'm trying to get to something to fix it.

Now, what does it need to implement something. A project is implemented by either the PTO, participating transmission owner, or an ISO making a proposal that a transmission line is needed. Then following the approval process within the ISO until the determination of the project being needed is made. Then going to the CPUC, the CEC and finally FERC.

Here's the TriValley example. You knew

it was going to come about. I knew it was going to come about, so try to keep prepared a little bit for it. Although it's been four years ago, memory's not one of my good items anymore.

Prior to 2000 we determined that a transmission grid inadequacy in the TriValley area of PG&E, which as Susan said, was Dublin, Pleasanton and Livermore area. We identified a preferred transmission project, and we decided to at least for the first time, try a pilot project to determine if there was any kind of an alternative to that transmission project that could be implemented which would eliminate or defer the transmission project.

We solicited a proposal from generation on load base alternatives, and we got rights for -- we told them we needed approximately 175 megawatts of capacity in any quantity between 1 megawatt to 49 megawatts per resource. And we got four entities submitting responses for a total of 264 megawatts of generation and approximately 30 megawatts of demand response.

Then we went into an analysis of the alternatives. Now, the generation and load management proposals achieved the goal of eliminating the overloads and the voltage problems for the next five years. The savings from deferring the transmission project for five years did not justify the cost of the generation of the load management proposal; and the transmission project chosen as least cost solution.

Now, why you would have a problem with this. One was a decision to look at a transmission project being deferred five years, as opposed to being eliminated. By the way the bullets that I'm giving you now are not -- I just added them a few minutes ago. This is the stuff that we need to probably discuss -- some point in time.

The second one is in order to put a generator in the area that we're talking about, and if you remember this area, this is a very nice, probably middle income area in the PG&E service territory, required the type of equipment that would be used would be different. And they want -- they work in a more commercial type of an arena.

For example, instead of having something that would be a combined cycle, this became a single cycle machines. That raises the cost. The cost of fuel is higher; the cost of taxes is higher; the cost of cooling is higher; and plenty other items.

That makes this generation projects extremely expensive and probably one of the reasons that they were not selected. Of course, the demand side of 30 megawatts did not meet the problems of 175 megawatts, so they were not selected.

One of the problems we have and we're going to be looking at having generation be a substitution for transmission is a transmission project receives revenue requirements authorization from FERC. A generation project that's going to substitute for a transmission project does not.

So basically we have a problem if you're to ask a generator to move from location A, which was cheap, to location B which is not as cheap, there is a penalty that has to be paid. The question is who's going to pay that penalty. Honestly, we cannot pay it. I don't think there's anybody around right now that can pay that penalty. There's no process or procedure in place to do that.

The second one is if you are depending on a single or generator to solve your problems that looks awfully lot like an RMR requirement. And the question is are you also going to have to issue an RMR contract with this generator, which ought to be taken into account when you do the economic analysis.

The third is you're comparing the long-term lumpy transmission line projects to the nonwires alternatives. By lumpy means I cannot build a 230 kV line of 50 megawatts. When I build the 230 kV line I get 350, 400, 600 whatever the number is. But you build transmission in all kinds of sizes. You can do demand side size in all kinds of sizes. So, is $1 per megawatt item comparison appropriate.

Also, how do you evaluate the fact that transmission has a different -- is a different product than generation. If the generation is off I don't have anything. It is unlikely that the transmission line will be off for any amount of length of time. But I can have all kinds of resources available to me to put into the transmission line to solve the problem I have at the other end. So what is the appropriate comparison.

The next question on this one that has to be answered is are we saying that we should defer the transmission line by the length of the contract. Or should we eliminate the transmission line. In most cases you need to worry about the fact that in five years load growth may eliminate -- may bring back the problem that you had initially. With the transmission line there you're still okay. With the ultimate solution you may not be okay.

So what do we need to do. Well, we need to have the state and the ISO, the state agencies and the ISO work together to integrate state planning and procurement proceedings with our grid planning process. And we're ready and available to do that at your command.

There are ways of maybe possibly recovering the costs -- with this generation; maybe the CPUC can do it. Authorize the PTOs to recover that.

What i think the objective of this process is that all the costs and all the benefit have to be considered in the proper light. And we need to make sure that the right project is brought back to the ratepayers. That makes economic sense.

That's all I have. Be happy to answer any questions now or a little bit later.

PRESIDING MEMBER GEESMAN: I have one, Armie.

MR. PEREZ: Yes, sir.

PRESIDING MEMBER GEESMAN: And it's in the broader sense of trying to optimize our investments in generation versus transmission or nonwires alternatives. And that is reflecting on both your experience at the ISO and before that at Southern California Edison.

Are there white elephant transmission projects, or stranded asset transmission projects, projects that aren't fully utilized, projects that we simply shouldn't have invested in?

MR. PEREZ: Not to my knowledge. And I also mention a quote that I got from a high level official at LADWP that make the statement I have never invested in a transmission project that lost money. Not one.

PRESIDING MEMBER GEESMAN: I think there are important environmental issues that need to be considered and public health and safety issues.

But I'm trying to get a handle on what, to me, seems this elusive holy grail of trying to optimize public investments. And I'm not aware of a stranded asset problem in transmission or the white elephant problem.

MR. PEREZ: The other problem that we have, Mr. Geesman, is that there's an inherent value of insurance associated with a little bit more amount of transmission than you require. And that comes about clearly every time I talk to an operator. And believe me, I spend half my life in operations, half my life in planning, so I know how they both speak and what they want.

There's never enough transmission for an operator to be happy. And they're always going to come back to me on the peak of the year and say, see, I have 25 generators off and three transmission lines out, and you planned the system for one generator off and one line off. What do you want me to do. And I says, well, you're only on that predicament for one hour. So.

PRESIDING MEMBER GEESMAN: Thank you.

MR. KONDOLEON: Okay, the next presentation will be provided by Barbara Hale from the California Public Utilities Commission.

MS. HALE: Good morning, Commissioners, folks in the audience. I'm pleased to be here to represent the Public Utilities Commission today. My name is Barbara Hale; I'm Director of Strategic Planning at the Commission. I came when Don and Kristy indicated they needed someone from the Public Utilities Commission to talk about how we were going to be working towards integrating the investor-owned utilities' efforts at resource procurement.

Where we consider not just generation and DG and some of the other kinds of resources and transmission that we've been talking about today, but in the broader effort of planning ahead for meeting California's reliable electric service in the most cost effective and environmentally sensitive way.

Let me talk just a little bit, for purposes of history, about the energy action plan where our agency, the PUC, the Energy Commission and the California Power Authority got together, and in the context of that effort, identified a loading order of resources for California that states a preference for what resources should we go for first, if you will.

And in our energy action plan efforts, which were adopted by all three agencies by May of '03, a loading order was identified and is being pursued by the Public Utilities Commission for purposes of the investor-owned utilities. That loading order says that California should pursue all cost effective energy efficiency first, all demand response that's cost effective, and move on down the line to distributed generation, renewable generation, fossil generation.

And simultaneous to pursuing those different resources, also pursue all needed transmission upgrades.

The Public Utilities Commission, since that May '03 timeframe, has been implementing that broad policy statement via a number of proceedings. And I will try not to do the PUC-speak thing where I rattle off a bunch of proceeding numbers, but I am happy to help you identify what particular proceedings are in a separate conversation offline from here.

We are pursuing this effort in our procurement docket and had identified in December orders and in our more recent January order this very loading order and how we were going to pursue this loading order with the investor-owned utilities.

We recently adopted a new procurement proceeding, our integrated procurement plan proceeding where we're sort of looking at that as an umbrella proceeding, allowing us to incorporate what we learn in that docket, as well as our energy efficiency docket, our demand response docket. Both those dockets are dockets where the Public Utilities Commission and Energy Commission Staff have been working in a very collaborative way, very constructive and collaborative way.

As well as our distributed generation docket, again, we have collaborative staff working there. Our renewable procurement standards docket; again collaborative staff between the PUC and the Energy Commission, identifying the best steps forward.

And then also our transmission planning and permitting streamlining proceedings where, as President Peevey would say if he were here, we would agree to disagree amicably. We don't have collaborative staff efforts ongoing there, because I guess that's where we're agreeing to disagree.

We recently issued in that docket, that

umbrella docket, that procurement, new procurement docket, a ruling that lays out more specifically how we are integrating these different resources and doing a comparative analysis through scenario planning for the investor-owned utilities.

We've specifically identified assumptions the investor-owned utilities are to incorporate into the long-term plans that they will be filing on July 9th of this year. And we've identified a target date for a decision on those procurement plans of December this year, 2004, December 16th.

Let me talk just a little bit about the different assumptions that are going in that we've directed the investor-owned utilities to put into those procurement plans. Because that's how you'll start to see how the Public Utilities Commission is going to implement this comparative analysis we've been talking about today for, as I say, for the investor-owned utilities.

I recognize that the Energy Commission has a broader statewide perspective; the Public Utilities is only responsible for the investor-owned utilities.

So, let's talk a little bit about then

the specific assumptions. For demand side aspects we directed the investor-owned utilities to incorporate energy efficiency program impacts; describe committed versus uncommitted; annual energy and peak impacts.

For demand response programs and tariffs we've directed them to describe which programs are net from the demand forecast; and the annual peak impact by program. We've directed them to identify self-generation and distributed generation opportunities.

We've also, on the supply side, specifically directed them to incorporate assumptions about the availability and operating characteristics of their existing utility-owned generation; energy available from utility-owned or -controlled hydro units; energy from QF contracts; energy, dependable capacity from existing and future renewable portfolio standard contracts. The costs and revenue from market sales and purchases of electricity. Natural gas components.

The operating characteristics of other new resources that they expect to meet utility needs going forward, including baseload energy on a year-round basis; load-following services for high-load periods; as well as on a year-round basis; peaking energy needs.

We've asked them to be very specific in terms of identifying energy purchases specifically tied to a new transmission system upgrade. Should they have a specific energy purchase that they're identifying in their plan, they have to be specific about whether it's going to require a transmission upgrade.

We're telling them to also be very specific about deliverability of any resources. We've run -- Mr. Perez and I have had many conversations about how frustrating it is to look at the utility plans, look at the system operations and see that there's just resources that can't get to the load where it's needed.

We directed the investor-owned utilities to be specific about local reliability concerns. TriValley was an example Ms. Lee talked about that was providing some local reliability for an area. We recognize that that's a very important part of what the current makeup of the system is in need of, is a very more granular look, not just an investor-owned utility service territory-wide look it needs, but a more granular look at the local reliability level.

PRESIDING MEMBER GEESMAN: How granular have you gotten in trying to define local reliability?

MS. HALE: The investor-owned utilities are aware of the load pockets in their service territories. You know, they certainly have been working with the ISO through their annual transmission grid planning plans and identifying those; and being specific.

We haven't seen them bring in a more specific plan yet. That will be coming in, Commissioner, on July 9th, responsive to that local liability concern.

PRESIDING MEMBER GEESMAN: Do you then envision using the ISO's local area reliability framework?

MS. HALE: Yes, that's certainly an aspect of it. Another example is the SDG&E request for offers that addressed some specific local reliability concerns they had. And the Commission recently adopted a decision after evaluating those proposals. The Otay Mesa, Palomar, renewables and energy efficiency programs that were put forward for authorization by SDG&E.

That's an example of us acting on a more local reliability concern.

But we expect to get more granular data in this July 9th filing from the investor-owned utilities. And we've also asked them to be very specific about transmission system upgrades. For any transmission system upgrades they've been directed to document a description of the upgrade, the purpose of the line, the transfer capability, any expected impacts on transfer capability of other components of the transmission system; provide a ballpark estimate of the investment and annual operating costs of the upgrade; the current status of the planning and desired online date; and to explain how the project functions as part of a balanced portfolio.

The investor-owned utilities, as I think Ms. Lee talked about, and Mr. Perez, bring in an annual transmission plan to the ISO. That plan and what it reveals to the state's decisionmakers is going to be a part of what we look at as we look at the investor-owned utilities' plans.

We're expecting to see a lot of commonality between what they're proposing to the ISO and what they're proposing to the PUC. We're hoping that by integrating these other resource options earlier on in the procurement process, before we get to permitting which Susan talked about, Ms. lee talked about, we'll be able to see more of the choices; look at more of the options earlier on in the process, as Ms. Lee identified as a current problem with the process. And that way be able to follow through on resource planning going forward.

All of these resource plans, though, I think it's important for us to recognize, are part of an integrated -- struggling for the word -- an iterative process. What comes to the PUC this year in procurement plans is going to be an outlook for resource planning for many years into the future.

The same sorts of information will be part of the Integrated Energy Policy Report effort for '05. The forecasts that come out of the Energy Commission's effort in the IEPR are going to form the basecase for the scenarios that the investor-owned utilities file with the PUC.

So it goes around and around every two-year cycle or so. So we're constantly reassessing, you know, how has California's load growth changed. How has local reliability changed. What are the current needs. Are there new technologies that need to be integrated into this resource planning effort.

And through that iterative process we'll just sort of have a rolling out of resources as we go forward. And hopefully it will provide the marketplace with the kind of assurances for investment recovery that will get new resources, new efficiency programs, new demand response programs, new generation alternatives, as well as transmission investments made for California.

I talked mostly about our procurement umbrella proceeding. I also want to just touch briefly on the fact that we are working with the ISO on streamlining our permitting process. Ms. Lee talked a little bit about the permitting process at the Commission for transmission. It is where we identify whether a project is needed; what its total cost is; whether it meets the California Environmental Quality Act requirements.

And we recognize that that's an effort that needs to be streamlined in order to get these resources that are needed constructed in a timely way. And to avoid any duplication of effort among state agencies. The ISO has recently filed with us an economic methodology that we're hoping will be able to evaluate and agree is the appropriate method for assessing the need of all transmission projects in the state.

And then we won't need to repeat the need effort at the PUC when the investor-owned utility brings forward a proposal.

And I would commend to you a report that staff prepared that's attached to the rulemaking, itself, that talks about, you know, sort of what the broader problems are with transmission infrastructure development in California, at least from the PUC Staff's perspective with respect to investor-owned utility investments. And how generation and transmission are sort of chasing each other around the state.

It brings in the federal efforts, too, and how California's permitting and planning process needs to mesh well with the federal process.

And so with that I'd be happy to answer any questions folks may have.

PRESIDING MEMBER GEESMAN: Barbara, I want to thank you for being here today. Your

Commission, I think, quite recently directed Edison to file a CPCN on Tehachapi.

MS. HALE: Yes, we had a Commission business meeting last week where the Commission adopted an order that directed further study on the Tehachapi corridor ideas to bring that potential renewable resource into the load centers. And specifically directed Edison within six months to file a CPCN for the early phases of such a project.

PRESIDING MEMBER GEESMAN: Now, we've certainly heard in this workshop process quite a bit about the necessity of added transmission capacity to harvest some of our state's renewable resource. And I think that would be something that our Commission was quite interested in seeing accomplished.

It's not clear to me, though, that a project like that fits in terms of what Mr. Perez was speaking about, either their reliability category of transmission upgrades or their economic category of transmission upgrades.

Do you see this as a third type of transmission project? And if so, how would you propose that the state evaluate it?

MS. HALE: Yes, I do see it as sort of a third type. And I see it as a third type based on the fact that the Legislature directed us by new law to bring renewable resources into the load centers in California.

So, yes, I do see it as a different effort. And I do believe that the analysis, the criteria for whether a project should go forward are going to need to take into account that new law.

PRESIDING MEMBER GEESMAN: How do we do that?

MS. HALE: Well, I think the CPCN that Edison brings in will begin to shape that. I think we at the Commission, through the renewable portfolio standard docket and in the transmission planning docket of giving the utilities some direction on that, where we are looking at, you know, how do you assess the costs; who pays. It's going to have an influence on the need and economic evaluation of the project.

But the bottomline is we've been directed to increase the state's reliance on renewable resources. The Energy Commission very helpfully, pursuant to the law, put together an assessment of where those renewable resource potentials locations are in California. Many of them are remote. And that does put a lot of pressure on building new transmission infrastructure to bring those projects in toward load.

So we are breaking new ground and looking at a new way of assessing these projects.

PRESIDING MEMBER GEESMAN: Thank you.

COMMISSIONER BOYD: Barbara, I just want to echo Commissioner Geesman's thanks to you for being here today. I appreciate your recognition of the fact that you are dealing jut with the investor-owned utilities and so mutually, through the energy action plan and what other devices we have, we all collectively need to look at a broader picture.

And kind of just building on what Ms. Lee introduced, and Mr. Perez reinforced in my mind, I just didn't push the issue, though, that, you know, we really need to take into account so many other societal needs and priorities in putting these systems together. I mean we do need to look at the whole system.

I sit here worrying about, I broached

earlier, you know,, natural gas system adequacy. I also need to concern myself about transportation fuel adequacy in the future, and I don't just mean conventional petroleum fuels. We are looking for that hydrogen highway. We are looking at alternatives.

I mean just so many -- we're looking at security issues that we never valued before. I worry about, as I'm sure you do, too, that electricity failures and weaknesses can bring down other parts of the economy that are vital, such as, you know, keeping the natural gas moving or keeping transportation fuels moving; or making sure refineries can run even if there's blackness around them.

There's so many things we need to integrate into this that we have a lifetime of work. And I don't have a lifetime left to devote to it.

But, these are just all the issues we have to put into the system, so it is going to take all the agencies who are working together here and who expressed an interest in the various pieces for which they're responsible to integrate this all together.

So, I'm gratified by what I've seen over the past couple years versus what I was introduced to four or five years ago. So, thanks for being here.

MS. HALE: Thank you for having me.

MR. KONDOLEON: Thank you, Barbara. I just want to remind folks Barbara touched briefly on the fact that the ISO has recently filed with the PUC the report on the transmission economic assessment methodology. And there will be a presentation in the afternoon session by ISO Staff on that filing. So, just to remind folks of that.

Our next presentation will be made by Ed Smeloff, representing the San Francisco Public Utilities Commission. Welcome, Ed.

MR. SMELOFF: Good morning, Commissioners Geesman and Boyd. I'm Ed Smeloff; I'm the Assistant General Manager for Power Policy Planning and Resource Development at the San Francisco Public Utilities Commission.

And I'm here today to discuss with you a local area perspective on planning for alternatives for transmission projects.

I wanted to present to you the San Francisco planning context, what we've been doing in San Francisco over the last three years or so in terms of developing an electricity resource plan evaluating alternative projects.

I'd also like to discuss some of the analytical issues that are involved in comparing distributed generation and demand side management to transmission expansion; and make some suggestions about the need to focus in a more granular manner, particularly within the Bay Area on planning for transmission alternatives.

So to give you sort of the broader context, as others have noted, we had a blackout in December of 1998 that led to a process that was led by the Independent System Operator to look at alternative transmission projects to lessen the probability of a similar type of blackout. That blackout was caused by a problem at the San Mateo substation which is on a limited set of transmission lines that come into San Francisco.

The process that was initiated led to the recommendation of the prioritization of the Jefferson-Martin transmission line in December of 2000 by the stakeholder committee; and then brought forward to the ISO and they recommended going forward with the project in April of 2002.

Roughly at the same time in May of 2000 Mirant submitted their application for certification to you for a 540 megawatt combined cycle power plant in San Francisco at the location of the existing Potrero plant. So we were confronted with having two alternatives for improving reliability in San Francisco.

Around that time the board of supervisors in San Francisco passed an ordinance that directed us, the PUC, and our department of the environment to develop a long-term electricity resource plan for San Francisco and look at ways of maximizing the implementation of renewable resources, conservation, load shifting and transmission projects.

At the time PG&E was forecasting, you will recall this was in the midst of the dotcom exuberance and PG&E was forecasting fairly significant increases in load growth within San Francisco.

San Francisco and the Peninsula have a very vulnerable transmission system; it's not a loop system. All of the electricity comes up the Peninsula; follows a single corridor through the San Mateo substation to the Martin substation.

And then a series of underground transmission lines deliver that into San Francisco, both 230 kV and 115 kV generation.

San Francisco also has old and vulnerable, highly polluting, inCity generation. The Hunter's Point plant is 44 years old; the Potrero plant is 37 years old. Beyond their normal useful life, but continue to operate because of reliability needs.

The City of San Francisco and PG&E have agreed to shut down Hunter's Point as soon as it's determined by the ISO that it's no longer needed for reliability purposes.

San Francisco is somewhat different than the state in terms of its peak demand for electricity. Peak demand can virtually occur in San Francisco in any month. Typically it doesn't occur coincident with the statewide peak. It's rarely when we see July or August as peak months in San Francisco. But we have both a winter peak and a summer peak. Obviously this has an impact on what resources you can plan for that would be alternatives to transmission. They have to be capable of providing the electricity at periods of time that are broader than we might see PG&E-area-

wide.

In putting together an electricity plan for San Francisco we took an approach which we call scenario analysis. We built three different resource scenarios around the resources that we projected to be available within the next five years or so.

One scenario we called the central generation scenario we built around the Mirant-proposed Potrero 7 power plant. The second was relying more on imports into San Francisco, which ad as its central feature the Jefferson-Martin transmission line. And then a third scenario that relied on more distributed resources, both small-scale generation, solar and other available renewables that can be sited in the Peninsula and the City, and energy efficiency projects.

We used these scenarios to stimulate a public discussion in San Francisco. And we had a fairly broad-based discussion that lasted for many months, almost a year, to result in the recommended set of projects and resources that were to be developed in San Francisco.

Again, this just summarizes the three scenarios that we had put together. They had different levels of commitment to energy efficiency, solar and distributed generation, with the distributed resources scenario having the most aggressive set of resources from those technologies.

We did some analysis in terms of reliability, what the reserve margin of each scenario produced; as well as measurements of emissions of NOx, PM10 and carbon dioxide. We also looked at the costs from a societal perspective. A very interesting set of issues when you get into scenario planning in terms of who pays and who benefits. And there's a very different set of issues related to how investments are made in distributed generation versus central generation versus transmission.

From a societal perspective in looking at these three scenarios, the costs over the ten-year time horizon were roughly the same in each case. The scenarios each produced an improvement in electric reliability and significantly reduced pollution by allowing the retirement of some of the older facilities.

But there were significant differences in both the risks of implementation of each of the scenarios, as well as the distribution of both the benefits and costs.

On the central generation scenario there was a major environmental justice issue. While the large power plant proposed at Potrero would have reduced emissions of NOx regionwide by displacing generation elsewhere, it actually would result in increasing NOx and PM10 emissions within the immediate area around the plant. So, some major issues related to environmental justice.

Similarly, on the distributed resources scenario that scenario had economic impacts in terms of economic development, job creation opportunities within the area as a result of more focused inCity development of these resources.

But there were significant risks associated with each of the scenarios. Obviously with the central generation there was great regulatory uncertainty, and there was significant changes in market conditions after the AFC was submitted that, at the time we were planning, gave us some hesitance about the possible delay of that project.

For the more import scenario there was significant opposition that we were seeing developed in San Mateo County, which we thought at the time may have had potential for delay of that project beyond the 2005 time horizon. In addition, Jefferson-Martin, while it solved some reliability by separating corridors between San Mateo and the Jefferson substations, both of them still terminate at the Martin substation. So there still is some risk, significant risk to the City of catastrophic failure at Martin.

For the distributed resources scenario we had proposed siting an appropriate amount of small combustion turbine generation. The City, it was a question at that time, and I think still a question of the City's ability to finance and complete the siting of that generation.

I wanted to mention that we had, in the distributed resources scenario, forecasted a fairly significant amount of local distributed generation principally in the large office structures within San Francisco. And we have discussed with a number of developers the opportunities that they saw in those structures.

There's some real significant hurdles, though. The discount rate that office owners expect, the sort of financial hurdles, means that if there is not a very quick payback these projects are not likely to be developed.

And in addition to that, because they're on the network system that serves downtown San Francisco, there's a lot of uncertainty about the details of interconnection which can cause delay and financial uncertainty both for the developers and for the office holders. So we have seen a slower than anticipated amount of distributed generation in San Francisco.

And then on the distributed resources there was also the risk that the political support necessary to maintain a high level of investment in energy efficiency and solar through the public goods charge and other mechanisms may wane.

So our electricity resource plan made a series of recommendations, many of which were followed through on. A key recommendation was for the City to get more involved, to take additional responsibility in both planning for and procuring new sources of power generation, as well as more involvement in energy efficiency and demand reduction programs within San Francisco.

We also suggested at that time that we identify opportunities in the 2001/2002 timeframe to develop alternative generation projects in the event that the Potrero 7 plant was not built. And it's becoming clear to us that that project is very challenged.

There was a broad agreement that the Jefferson-Martin project needed to be supported, and that the ISO and PG&E should come together to identify other needed projects, both within the City of San Francisco and to the south of Jefferson and south of San Mateo substations. And that the City also should move forward and aggressively implement energy efficiency and solar projects on municipal facilities where we are the electric service provider through the Hetch Hetchy water and power system.

Just want to give you a quick overview of where we are now on the implementation of our electricity resource plan. As you know, we've submitted to you an application for certification for three combustion turbines to be located at the Potrero Power Plant.

Just recently last week the Public Utilities Commission made a proposed decision to approve the Jefferson-Martin transmission project. And that seems to be proceeding forward in a positive way.

PG&E and the City, through the department of the environment, are implementing a targeted energy efficiency program with a goal of reducing load in San Francisco by 16 megawatts.

The Public Utilities Commission, where I work, is now budgeting annually approximately about $7 million for solar and municipal energy efficiency measures. They have about 1.5 megawatts of new solar projects in the pipeline to be developed; completed the first project at the Moscone Convention Center, which has been up and operating for about three months now.

As I mentioned, we have seen companies come to San Francisco, Northern Power and RealEnergy, and have shown an interest in developing distributed generation projects, but have encountered a number of obstacles. Some of it dealing with the uncertainty about what the future retail rate for electricity is going to be, which impacts the time horizon in which they would recover the investments in distributed generation.

The ISO has agreed in writing that Hunter's Point would shut down with the siting of our combustion turbines. And with specific transmission improvements, not including the Jefferson-Martin project.

And then more recently PG&E has made the case and has asked the ISO for agreement that even if the combustion turbines are not developed that the Hunter's Point power plant could be closed at the completion of Jefferson-Martin and other transmission projects.

Now I'd like to move on to what we would need in San Francisco to really improve the process of evaluating whether distributed resources can act as a realistic alternative to transmission. And it would mean, as you've heard several of the other speakers, to be looking forward in time to what projects would be needed over the next five- to ten-year time horizon; develop capital budgets for those projects; have a better understanding of both timing and costs of transmission projects that would be proposed.

We would then need to have, I think, more fine-grained information on loads by class and by small geographical area; and the growth rates that are likely to occur within those groupings of electrical load.

This would allow us then to better

compare the ability of distributed generation, demand side management projects to defer, or perhaps even cancel, eliminate the need for transmission projects.

We also would need a mechanism, rather than right now where it's somewhat sporadic in terms of what DG projects are being proposed; and based on the ability of developers to market those projects in the interests of specific property owners, a better way to identify and to prioritize distributed generation projects within an area like San Francisco or the Bay Area in general.

And then to also create more certainty about any cost recovery that might be proposed for the value of the grid enhancements these projects bring. Right now the planning is simply done on the value of the energy of those projects to the property owner. And similarly we would need to be better able to target demand side management programs that are funded by public goods charge and other mechanisms by area and by time.

I think it's important that we take an integrated marginal cost approach to determining the value of distributed generation and demand side management. We need to combine both the marginal cost of the local transmission and distribution projects that might be deferred by distributed generation or DSM portfolio, together with the marginal energy costs, the capacity costs of the energy portion of the project.

And, as I mentioned, in San Francisco we need to make sure that the projects provide the resource, provide the electricity and the relief on congestion at the times that they're needed within the system. And it may be different in a small area than it is regionwide.

So, I'd like to end my presentation by suggesting that there is a -- we've established in San Francisco and the Peninsula a precedent for doing some regional planning. The ISO and PG&E have been very cooperative. There is a phase two now for a Peninsula transmission study that the ISO is hosting. It would be helpful if the utilities, as in some other states like Vermont, would be required to engage in a least-cost transmission and distribution planning for small areas.

And those could be assisted by something like has occurred in San Francisco where there would be a regional collaborative that would take responsibility for working with the distribution utility to determine what the avoided costs are for transmission and distribution; identify potential DSM and distributed generation alternatives; and then to recommend an implementation plan that would allow for assured cost recovery of any alternatives for the transmission projects.

I want to mention, I think the Bay Area would be an excellent location for a collaborative, building on the processes that we've already developed, but taking it on a more regional basis to look at projected transmission projects regionally, and compare it to what potential new generation projects, distributed generation projects, could be available. And couple that to plans for looking at the potential for retiring some of the other older units within the Bay Area.

So, let me end it there, and I'd be glad to answer any of your questions.

PRESIDING MEMBER GEESMAN: Ed, thanks for your presentation. You're probably further along by a long shot than any of the other regions within California in terms of planning and a fair amount of exposure to the investor-owned utility process.

How far off do you think that the status quo distributed generation planning process, or the transmission planning process is from what you characterize as a least-cost planning process?

MR. SMELOFF: I think we're still quite a ways away from having a process that fully evaluated both the technical and economic potential for distributed generation, and compared that on a apples-to-apples equivalent basis with transmission alternatives.

I think there is, in the Bay Area there is interest in doing this. There's, I think PG&E has been engaged in a community participation process for the last two years, and I think would be interested in trying to provide some more fine-grained analysis, both at the transmission; and I think you need to take it down to the distribution level as well.

But I think that we're still a significant ways away from being able to effectively compare distributed generation and DSM to transmission alternatives.

PRESIDING MEMBER GEESMAN: Thank you.

MR. KONDOLEON: Thanks, Ed. The next presentation will be provided by Greg Karras representing Communities for a Better Environment.

MR. KARRAS: Thank you. We're plugging in a different technology here. And I have to tell you, I brought a transmission line just in case.

(Laughter.)

MR. KARRAS: I'm Greg Karras with Communities for a Better Environment, a Senior Scientist with CBE. And I also brought another-- where can I plug this in?

(Laughter.)

MR. KARRAS: Yeah, it's a USP line. And I'm just trying to make the point that the design of the circuit affects what we can plug into it. And, you guys, of course, do have USP ports. No, this is just a prop.

(Laughter.)

MR. KARRAS: Sorry about that. I didn't mean to play a joke on anybody, I'm just trying to make the point that the circuit design, the grid design support. I think you need to be re-engineering the grid to plug in the stuff we need to be plugging in, instead of the stuff that we need to be getting rid of. And I've got a couple of slides to show on that.

The first one is a quote from some people smarter than me that sort of said the same thing in a broader way. This is from the Journal of Science article a couple years ago. I think everybody can see that. Maybe I'll just read it in case.

Advanced electrical grids would also foster renewables. Existing grids could not manage the loads. Present hub-and-spoke networks were designed for central power plants. Such networks need to be re-engineered.

So, even making the decision to build on to the existing system is making a choice about our energy future. And briefly, I just want to remind us of some, just some of the costs of choosing to build onto the existing system. These are things that are happening already, and there's good evidence that they will worsen if we keep doing this.

First, people said this already today in a couple different ways, but I want to put it in the perspective of transitioning to sustainable energy. Building big wires and big, I'd say, chunks, I think Armando used a different term, that then plug in central generation in big chunks, instead of small wires, or another system that works better for distributed generation will further undermine the reliability advantage of the distributed renewable technologies.

They are more reliable. If you put together a DG system with renewables, the biggest single piece that could go down is much much smaller than a big power line or a big power plant where we're talking hundreds of megawatts at a time; much less backup; much less cost to build that backup.

But if you keep building on the old system you're taking that advantage away on the short term because whatever resource you put in place, whether it's renewable DG or power plants, sill needs to provide all that backup for the biggest part of the system that could go down. Which, under existing reliability criteria, includes big power lines as well as big power plants.

So if you build onto the old system you're actively making a choice that discourages the ramp up of DG renewables. And that's just a fact.

Also, continuing to build big blocks of big wire capacity instead of building the small wire capacity I'll call it, more incrementally, it actually increases future load, itself. And this isn't complicated.

You know what happens when you buy a bigger bag, right? You fill it up. If you build a big block, demand increases faster. And you see that demand is above what's actually necessary. You saw it in 2001 where it dropped by about 10 percent when people were told to conserve, instead of being told there's plenty of capacity, fill it up. So, it actually does increase load.

Next, with load increasing faster and the system set up to plug in central generation stations, guess what gets run and what gets built more of. More fossil fuel power plants. Just like in 2001 when that happened.

So, all of this then perpetuates environmental injustice, the health problems, and the increasing erosion of public support for new energy projects that I think you already see, and we in the community certainly feel.

Meanwhile the easily mined North

American oil and gas is largely gone. And so going this way means that economics and geography will force more imports of these fuels which will also proliferate the development of fossil fuel extraction and manufacturing energy technologies worldwide even further than it is now.

Climate change. Let's bring it home. You know the Delta levee that broke a couple weeks ago? Did you know the State Water Project shut down because of salt in the water intrusion concerns? Well, American Association for Advancement of Science Panel on Climate Change predicted about 14 years ago that continued climate change would cause sea level rise and seasonal inter-annual changes in the amount of snow pack that was available for runoff. That's going to force salt water into the Delta. It's going to cause these pumps to have to shut down.

And I think you know that the state and federal Water Project supply food production and drinking water for millions of people here, because that's a big deal. And that's coming soon. Hopefully not for a few years; hopefully not for 50 years, but it's on that kind of horizon.

Then, again, I'm just listing some of the costs, but just to paint the picture. Increasing competition for fossil fuels worldwide, demand in China, demand in India, the inequities about that. That's a global security problem already; it will worsen; it will become an increasing contributing cause for war if we go this route.

And all of these have costs that can't be externalized. The fuels become more and more expensive. I think already you're seeing this. The price spike for oil, which is due to limited supply and security concerns now, is dampening an economic recovery right after a price spike for natural gas in 2000/2001 contributed to the energy fiasco that deepened our last recession. So it's already happening; it's going to get worse with energy prices going up.

And, of course, when I say reliability is only a part of this sustainability issue, ultimately when the price of the fuel gets too high we can have the best chimneys in the world, nothing to burn in them, the lights go out big time, right. That's not a reliability problem that gets looked at on a year-to-year or even decade-to-decade basis by the existing criteria.

But unsustainable energy is not reliable in the long term. And that's where the big problem with reliability comes in, I think.

And then I guess I'd ask you don't ask when or how long till the fuels run out. I think that's the wrong question. Ask how long can we afford to wait before we start to build a sustainable energy system. And here's where I think that the idea of looking at an alternative grid really becomes timely.

As I understand it if you build on the hub-and-spoke grid central generation plants and that grid will be around for 30 to 50 years, the new components of it will, what can happen in 30 to 50 years. Well, in the example I just gave about the Delta, climate science tells us that we'll be faced with having to either rebuild two of the world's biggest water systems to get their intakes out of the Delta, or faced with drinking water and food supply disruption in the Central Valley and a lot of southern California.

I think the health problems will be worse, and those have economic effects that people aren't counting right now, as well as the human effects. But also consider the price. I don't know exactly how the spikes will go, but it's a fair bet that the price of the energy is going to increase dramatically. The predictions for global energy use, threefold, fourfold 30 to 50 years from now.

So if you wait, if you build more of the old system now thinking that when that wears out we'll start to invest in converting to sustainable energy, you could be looking at also having to build, rebuild a big water system and other infrastructure while you have an economy that's hobbled by energy prices on average triple what they are today.

The point is that the costs of the old energy regime may increase sufficiently to erode our ability to make the switch. And this may happen within the timeframe of the infrastructure that you decide to build now. So, it's only prudent to look at the alternative of rebuilding the grid; re-engineering it so that it actually works to plug in the stuff we need, and not the stuff we need to get rid of. And start doing that now.

And I think I've been talking for about

ten minutes. Would you like me to provide a slide and a quick discussion of how I think that this recommendation relates to what's already been done in San Francisco? Okay.

This table is some of the results from the planning level reliability analysis that the load forecasting and power flow analysis working group, which includes ISO, PG&E, staff, San Francisco, Ed Smeloff, myself, community members and some other agencies, CPUC attended some of the meetings.

The first column shows four scenarios. It shows the San Francisco fossil fuel generation; megawatts available, and the megawatts assumed to be online in the limiting planning contingency for reliability planning.

The second or middle column is the peak load forecast for San Francisco and the Peninsula for the year 2012. And the third column is the modeled load-serving capability in the limiting planning contingency.

Back to the first column, scenario A is really the existing system; 580 megawatts of existing power plants; 320 online. And the biggest one, one CT goes down under the criteria used now. Historic trend of demand side management, distributed generation. And that applies to the load forecast. You'll see that when more of that is added the load forecast is decreased. That's the way we modeled load, and the way it was actually modeled in the underlying estimate by PG&E.

Then B, C and D are, I don't know if anybody can read those, or should I read them out?

PRESIDING MEMBER GEESMAN: We can read them, but if you would briefly explain what is embodied in each of the three remaining scenarios.

MR. KARRAS: Okay. Yeah, they're additive. Scenario B adds on 190, roughly 200 megawatts of additional demand side management, distributed generation. This is a target that San Francisco's energy plan set. It's an assumption in this analysis. But it is a planned target. It may be exceeded, it may not be met, time will tell.

It also assumes the Jefferson-Martin line is in place; re-rates of the line south of the San Mateo substation, and an insulator replacement project at the San Mateo substation.

And you can see that one actually has

reduced load-serving capability. That's for two reasons. One, the second scenario assumes 200 megawatts of generation available, not 580, which is the existing situation. And the other one is that we found that the Jefferson-Martin line, as was mentioned earlier, it needs some additional finer scale reinforcements to the transmission system to be fully effective.

So the next scenario, the third one, C, the same 200 megawatts of generation, less than half of now. The same scenario as in B with one addition, which is internal cable projects in San Francisco. And with those you see the load-serving capability goes up higher than it is now, despite having less than half the generation. And it meets the planning reliability criteria.

Scenario D, the two changes there are zero megawatts fossil fuel generation assumption in San Francisco, and assuming that remaining operational needs like clearances for washing salt off lines, or components of the transmission system, have been resolved in other ways. And that one also meets the -- assuming that with those assumptions, also meets the planning reliability criteria.

So you can see this is a progression that goes from existing system to something that we probably shouldn't do because it reduces reliability to potentially all the way to no fossil fuel generation in San Francisco.

And the two other points I'd make, without it are that the difference between B and C really points out the value of focusing on -- you know, this is a small step towards looking at what we really need to have a grid that makes it easy to plug in DG and hard to plug in big power plants that pollute. But it's a step in that direction.

And I think you see the benefit of even taking that first step. We found a configuration that's significantly more reliable. And, of course, the internal cable projects are much smaller and less expensive than the Jefferson-Martin line, so you get the picture there.

Lastly, the 200 megawatts of demand side management, distributed generation. Again, we're not there. We're not at the kind of grid and grid management that makes it easier to plug in that new stuff. We're still in a place where it's a lot easier to plug in power plants. That's what it was made for; that's the way it's managed.

And it's my understanding that if anything Mr. Smeloff drastically understated the problem of getting PG&E and the system to cooperate with the interconnection of solar and other distributed generation. I think that even on the short term, before we completely implement the redesign to re-engineer grid, that more focus on helping interconnect in reality would help us achieve that.

That's really the two base barriers, interconnection difficulties, which are not technical, they're policy largely. And funding, which, in my opinion, is where the money that's now being spent on the RMR contracts for these dinosaur plants should go.

So, I have some recommendations but I think they're listed in the agenda materials. The one I'd want to -- the two I really want to focus or emphasize on are I really think that we need to be planning to re-engineer the grid for the new generation of technologies now. I don't think we can wait.

As I understand the time scales for these investments and how long this stuff gets hard-wired in once it's built, strongly recommend that that be part of your integrated plan. And that may be the centerpiece of your transmission portion of it. Because if we don't do that next generation it may not matter what else we do or don't do.

And the second one is sort of the recognition of how hard that might be to do. Based on experience I think it's a really good idea to follow the local communities' advice. I believe that there's been a lot of progress in that direction in the San Francisco example that Mr. Smeloff talked about.

I believe there's a long way to go there. And I'm talking about the difference between having Sacramento or Washington tell the local community, well, here's what you should have put here and we get to make the siting decision, and having ISO and PG&E devote their technical staff to this process where, among other things, we've worked out these kinds of solutions to try to figure out how to get there from here.

And that has community support, unlike the kind of power plant and power line projects that I think you've experienced, what kind of community support those have.

So the other suggestion is more a matter of environmental justice from my perspective, and I think political feasibility from your perspective.

And that's all I got for now.

PRESIDING MEMBER GEESMAN: When you talk about increasing our reliance on renewable technologies, as I think you're aware, this Commission, the Public Utilities Commission, the Power Authority all urged last year that we accelerate the state's 20 percent goal for renewables from 2017 to 2010. The Governor's embraced that acceleration, as well.

It would appear that that is likely to place a lot of reliance on the development of commercial scale windfarms and the increased development of California's geothermal resource.

I'm not saying that I can stretch the definition of distributed generation far enough to incorporate that type of configuration.

It seems real clear to me that we do need to re-engineer the grid in order to accommodate that, particularly on the wind side where you're dealing with an intermittent resource, which we're simply not accustomed to integrating in that large a volume.

But I wonder where you would actually put a place for those kind of resources, or what reaction you have to it. Both of which, I assume, are likely to require some pretty big wires in order to fully develop?

MR. KARRAS: I'm really glad you asked that. I was acutely aware that I left that part out of the presentation. I don't have the redesign of the system to present to you. But I do think it has to, on the short term, deal with how do you give priority to connecting those kinds of resources using the existing system or something like it, on the short term.

I don't know if it's an advanced dc line that's more efficient; or if it's just priority over the existing lines with a few twists and turns. But I think that should be part of your design, because of course you have to get there from here.

But I'd also encourage you to think bigger than that, as well as, of course, the case I made for thinking smaller than that. If we, you know, what happens if the attempts of coming up with a hydrogen or some other kind of battery for the solar and wind resources fail. We don't know they'll succeed; or even if they're technically economically feasible. We don't know what all of the potential environmental and social impacts of them are yet.

So I think it would be really wise to be thinking bigger. And, you know, remember that in Africa and parts of Asia they're not putting wires up for telephones. They've jumped over to wireless. And, you know, if you think big enough, as well as small enough, you might be able to start thinking about getting energy from a way where the sun never sets.

So, yes, I totally agree. But I would expand your question even further.

PRESIDING MEMBER GEESMAN: Thank you.

MR. KONDOLEON: Okay, the final phase of this morning's session will be a panel discussion on how, where and when alternatives should be assessed in the process. Kristy will be putting the name tags up, and we invite those that have agreed to participate in the panel discussion to take your seat. And I also want to welcome Joe Eto from the CERTS team, who has agreed to facilitate the panel discussion.

(Pause.)

MR. ETO: Thank you; my name is Joe Eto; I'm with the Consortium for Electric Reliability Technology Solutions. I'll give a longer introduction this afternoon as part of my prepared remarks. I've been asked to facilitate this session. I think in view of the time I'm going to ask each of the speakers to attempt to be brief and succinct. I look at this list; we have about 13 or 14 people registered, and I think there will be some others from the audience who may want to speak at the end.

In view of that I'd like to ask each of the speakers to limit their initial remarks to about three minutes. I'll try to keep time. I won't be too strict, but if it starts going significantly over I'll ask you to summarize and conclude.

I'm going to follow the order of the registrations that I have here on the agenda. Then we'll open it up at the end, but also invite the Commissioners to ask their questions first after each of the panelists have had their statement.

So let us start with Roland Schoettle

from Optimal Technologies.

MR. SCHOETTLE: Thank you very much. I am Roland Schoettle; I'm the CEO of Optimal Technologies.

A very short introduction to what Optimal does. We have developed a new optimization technology that allows us to look much deeper into the grid, if you will, with a higher degree of granularity than what is possible now.

Maybe a small example of what we have done with the help of the California ISO, we have looked at the June 14th outage that happened on June 14, 2000 in the lower Bay and Silicon Valley area. And on that particular day we assessed that the outage could have been avoided with different control interactions. That action would have been possible on that day, but the current tools could not see.

So the ability to take some of the problems that are being expressed today, looking at the granularity of the problem, being able to include very small resources into the grid. And I agree with Armie -- actually I agree with everyone here that it's really the grid that is the issue.

The interesting part of that, however, is defining what that actually is. The definition of what actually is the grid; how it is interconnected with difference pieces and so on, ends up being a rather interesting discussion.

And I would argue that we have a technology that allows us to look at that. So, from a perspective of giving kind of the big picture all the way to the small picture, and including all of the various aspects, including the ability to look at stuff that is not included in the regular supply/demand balance, if you will, and understanding where precisely you're outside the boundary, and understanding all the options that are available to you at the time, is, I believe, where the discussion really needs to focus on, on a technical side.

I'm a strong believer in that if you look at the grid as your asset, you know, your customer is your primary asset. But the grid, itself, is the asset. And not so much look at the individual components, which are important assets, I'm not discounting them at all, but understanding the grid in this kind of a granular, but yet holistic approach, is really where we need to go.

And with that, I'll turn it over to the next speaker. Thank you.

MR. ETO: Thank you, Roland. Commissioners, would you like to ask questions as we go through or at the end?

PRESIDING MEMBER GEESMAN: No, that may be too disruptive. Why don't we just go from speaker to speaker.

MR. ETO: Okay. Next speaker is Steven Kelly from the Independent Energy Producers. I skipped -- Dave Olsen is next, from the Center for Energy Efficiency and Renewable Technologies.

MR. OLSEN: Commissioners, thank you. I'd like to report very briefly on work being done in the Rocky Mountain area transmission study about making more use of existing transmission assets as an alternative to physical upgrades or new transmission construction.

RMATS, as it's known, is a follow-on to the SEAMS study group, the western interconnection, a westwide transmission expansion planning effort. RMATS was initiated by the governors of Wyoming and Utah last September.

As part of that earlier SG-WI work, Dean Perry of the Northwest Power Planning Council did a study of most of the major transmission paths in the western interconnection which found that most of the paths are constrained only a new number of hours per year. That notwithstanding, there's no available transmission capacity on most of those major paths. All of the long-term firm transmission is reserved under contract, but, in fact, it appears that there's a large number of hours per year in which thousands of megawatts could be transmitted around the system.

To explore this in more depth the Rocky Mountain area transmission study has a tariff and regulatory issues workgroup which is undertaking a case study of three particular constrained paths in the Rocky Mountain region that are all very important inter-regionally in the west.

What we're doing, with the assistance of a U.S. Department of Energy contract through the National Renewable Energy Laboratory is analyzing WECC data, looking at the actual physical flows on these three constrained paths. And then we are matching that against windpower output. We're using wind as the leading example here. Really it's a proxy for new resources being added to the system. But as an intermittent resource wind has more capability to accept some curtailment.

There's reason to believe that the hours of the highest constraint on these paths are actually also the hours of the lowest wind output, which may mean that wind projects would suffer very little economic penalty from being curtailed in order to be able to utilize the physical transmission capability that's there.

The significance of this, I think, is the three major parts. One is a timing issue. If, in fact, it turns out, if we demonstrate in the Rocky Mountains that there are thousands of megawatts of existing transmission capacity that could be utilized, for example, by wind projects, that's something that can be implemented very quickly, years before any new physical upgrades could be permitted and built.

So, in the very near term, over the next two, five, eight years, it might make it possible to connect a larger significant amount of wind and other new resources to the existing system.

This would also defer investment in new physical upgrades with some attendant public cost and environmental benefits. And it also could increase the transmission revenue to transmission owners, if, in fact, it turns out there are mechanisms available that would allow the transmission owners to increase utilization of their lines.

PacifiCorp is one utility that is very interested in this from that point of view, from an incremental transmission revenue point of view. Bonneville Power Administration also has a project to recalculate ATC, available transmission capacity, specifically toward these goals.

Some of the key mechanisms that we're looking at and that would be necessary in order to take advantage of this purportedly existing transmission capacity would include a new tariff or an amended tariff.

Right now there are long-term, firm service available and there is nonfirm service available. And even though the transmission line may be constrained, only ten hours a year if it is constrained at all, then there is no possibility of having firm transmission service across that path.

So in response to that the American Wind Energy Association has developed what they call a flexible firm tariff, or a curtailable firm tariff in which the number of hours of curtailment is limited contractually, set at some level, 200 hours a year or whatever is appropriate for that path. And with that kind of certainty that would enable power projects using this flexible firm or curtailable firm tariff to get their project financed and still be able to use that transmission.

Work underway right now is in process. We expect to be able to report by the end of July, so we'll have detailed analysis. It will be published as part of the Rocky Mountain area transmission service, but it's something -- it's a transmission study, but it's something to keep in mind as an alternative to new transmission construction.

MR. ETO: Thank you. Next we'll have Steven Kelly from the Independent Energy Producers.

MR. KELLY: Thank you, Commissioners. First, just specifically in response to the question as to how, where and when alternatives should be considered, I find it surprising we're asking some of these questions. I want to speak to that process a little bit because my perspective we ought to always be considering alternatives at all times when we're looking at transmission planning and siting. I think this is something Armie mentioned earlier. It's not something you do at a discrete point. It's something that you do through the planning process.

But I would like to talk about that planning process and focus your thoughts on that a little bit. Because again I -- some of us feel, those who have been here for a number of years in California, working with energy and transmission issues, there are a few stakeholders that have the time and persistence to stick in this process for the five years that it takes for some individual lines to go through.

But a lot of these issues are issues that were raised a number of years ago, and we've been struggling with them for some time about how are we going to integrate transmission planning into the energy environment in California, the west. Most of the problems stem from the disbursed amount or authorities and jurisdictions across the state agencies and the federal agencies and so forth.

Fundamentally I think we need to -- we need something similar to the energy action plan that this agency and the PUC and others joined with on the energy side, on the generation side, which lays out a vision of how, at least this state, and hopefully the western region, proposed to move forward and plan transmission.

And I think you need to plan in three different contexts. One is a long-term vision that deals with economic and reliability projects on a long-term basis. And this agency has talked about corridor planning. And that's got to be integrated into that.

The second level of planning is the short-term, the expedient planning to deal with the one- to five-year issues that have come up that we can't build new transmission lines for, but we need for reliability purposes.

I was struck by a ruling by Commissioner Peevey at the PUC that spoke about the need for building and scheduling generation and planning for transmission to meet reliability needs in the near term. Those kinds of things can be planned on a long-term basis, but certainly we need a process and mechanism that allows us to adapt our long-term plans to meet these kinds of contingencies where there's under-scheduling or infeasible schedules being followed at the ISO to increase transmission congestion rather than mitigate it.

And then finally, the third component needs to deal, particularly for California, with renewable RPS buildout. As was pointed out earlier that's somewhat different than an economic buildout; it's somewhat different than a reliability buildout. But we have strong laws in California, and they seem to be spreading across the region, that says that there is a desire, a preferred alternative in generation sector for a renewable component.

And it's not clear how that generation preference is going to be integrated into the transmission plans that are focused on economic buildout or reliability buildout. I think we need to take that into consideration.

And finally, in terms of the planning and the process, it's very very important that we have more transparency in how transmission planning is done. For someone as close as I am to this, and to be as confused as I am about how some of this plays out, and over what timeframes and so forth, it's troubling for someone who's further divorced from this system than I to try to understand this. And I think you'll find that the lack of transparency in the actual plans, and how the computer models are operated.

Right now at the PUC there's a debate going on about the transparency of the ISO's transmission planning process because they have some agreements, vendor agreements, that are proprietary that limit the distribution of some of the information in them. And I understand that. But we need to figure out a way to work through that so that more parties can get access to the transmission planning information, as well as I've argued, in the IEPR, the utility long-term generation to procure a planning process.

Because it's only through that transparency that all this is going to fit together and meld. And hopefully the understanding of what's happening will allow stakeholders, a lot of stakeholders who are not here, and policymakers to get more on board about the need for infrastructure development, and generation and transmission infrastructure investment. nd that's what's lacking, I think, today, too.

So I'll leave that for now and welcome your comments.

MR. ETO: Thank you. Next we'll hear from Mark Ward from the Los Angeles Department of Water and Power.

MR. WARD: I'm Mark Ward from the Los Angeles Department of Water and Power. I agree with Mr. Kelly, the alternatives to transmission should be part of the planning process right up front when considering new resources to any load. The entire idea of transmission is how do you get reliable transmission so that generation can serve loads, whether those loads are local or whether those loads are regional.

DWP back in 2000 started using the, or approved the 2000 integrated resource plan for the City of Los Angeles. Part of that plan was to provide one-half of the city's load growth on an annual basis with renewable resources.

As part of that plan marginal transmission costs are one of the first things that we consider as far as where the resources can be located in an economically justifiable manner for our loads.

And because of that particular consideration, Los Angeles has generally given its first consideration to local resources which was demonstrated with our acceptance of a bioconversion park that is currently being developed and is expected to be online somewhere in the 2008 to 2009 timeframe. That facility will be located inside the city's limits.

We were also looking at a new windfarm out in the Mojave area which will further utilize some of our existing transmission assets.

As such, we have been focusing on how can we utilize transmission assets better, and how can we utilize our existing infrastructure better, such that we aren't having to go out and build additional transmission lines.

Once I've said that, once we get into the 2009-2012 timeframe, the city, along with the rest of the state, is going to have to look at where are the future resources actually going to be. The state and the city have been experiencing load growth in the 1.5 to 2 percent range over the last several years. For the state that's 500 to 1000 megawatts annually; for the City of Los

Angeles it's about 60 to 80 megawatts annually for our load growth.

So, we support the Commission in identifying corridors. I think it's important to identify where the future resources are going to actually be. And it's important that we start dedicating assets from not only putting up hardwire and looking at how the state can insure its future viability.

Thank you.

MR. ETO: Thank you. Next speaker will be Morteza Sabet from the Western Area Power Administration.

MR. SABET: Good morning. I'd kind of like to beg to differ with some of the statements that were made earlier. I think transmission planning, there's nothing wrong with transmission planning and the processes that we have. As a matter of fact, I think we have too much dead weight right now in the planning process and planning discussion.

And the reason I say that is basically a personal experience that I've gone through. You know, we used to have, when I worked at this Commission promoting exotic technology, renewable demand side management back in the '70s after another crisis, life was a lot simpler. You had a lot less players, and the Commission could direct the utilities to look at alternatives. Even back then, if it didn't make economic sense it didn't happen.

I am also involved in renewable discussion, another project in this Commission, through Western's involvement. That's one of the difficulties. I think those utilities that used to control and demand are long gone; they're defanged, declawed and bankrupt. They no longer exist. No one entity has that much control over transmission planning anymore.

I think if the project is real, I extend that to distributed technology, demand side, as well as centralized or decentralized stations, small or large scale, if the project is real it will be considered in the transmission planning. Whether it's the ISO is doing it, utilities are doing it, or anybody.

Western, since we do not have the load growth obligation, by the very nature of the planning we seek out and insist on including all of the end use assumption, be it demand side or supply side, you know, assumption, as well as other people's transmission. You can't do your planning any other way.

So, I'm a little baffled in terms of what's wrong with the process. I think the process is working. We ought to reduce the number of institutional overhead and reduce the dead weight. I think we can do the job.

That's about it.

MR. ETO: Thank you. Next we'll hear from Chifong Thomas from Pacific Gas and Electric.

MS. THOMAS: As I was thinking about how we would be going through the integrated planning process I was struck by the fact that before we even think about alternative to transmission reinforcement we need to know what problem are we solving.

For example, if you are looking at a severe over load or voltage collapse problem or loss of a transmission or generation facility then we would -- and then you were trying to replace that with a generator, then that generator must be running during all those times you expect that the problem could happen, in anticipation of the loss of the facility.

In other words, if you think that a -- you're going to be facing with a problem on sudden loss of any facility, when the load is about 70 percent, then that generator that you want to replace the transmission will have to be online and running under all the time when the load is about 70 percent. That's one point.

The other is the fact that we need to match generation to the load because the load and resources balance must happen every instant. Because otherwise you would have all sorts of ugly problems, over frequency, under frequency, cascading.

The other thing that issue with integrating planning is that as you see how long it takes to plan a transmission line, and what we need to do is be cognizant of the fact that we don't want to add longer lead time when you put in also other alternatives. And so you don't want to be in a situation where five years down the road you don't have a generator and you don't have a load reduction and you don't have transmission.

Cost recovery. I agree with Armie that -- alternative should certainly be included in cost recovery. And also, too, that the money spent in siting transmission line later on find out was not needed because we have our alternative, will have to be recovered also. Because otherwise you put a damper on trying to figure out how to do integrated planning.

As far as the process is concerned, actually I agree with Morteza, it is pretty much an open book because the ISO, we had stakeholder meetings, we had basecase assumptions set with the stakeholders. We had the assessment that was laid out; the program that we use, which are basically commercial packages that you can get at General Electric, PTI or any other vendor. Also the data can be obtained from WECC. And also we regularly discuss problems and assessments in WECC and under ISO's purview.

So I would think that it is pretty much an open process. I think that's --

PRESIDING MEMBER GEESMAN: Let me jump in here. With respect to both of the last two speakers, it just doesn't look that way from my perspective. I have to confess to you a fundamental disagreement.

My example de jour is the Mission Miguel fiasco on the southern border of our state, where we knew with some degree of lead time that 1660 megawatts were coming online in the summer of 2003.

The process, I think, on this one was initiated at the Public Utilities Commission before it went to the ISO. In the fall of 2001, the parties stipulated to the economics of the project, agreed that it was all justified. This was a $31 million upgrade, so pretty small project by the standards of some of those that have gotten attention around the state before.

During the brief period of time I was on the ISO Board in the spring of '02, the project came to us and it was represented that even ORA was supportive of the project. And our board approved it. San Diego subsequently filed a CPCN.

I believe after that filing no action was taken whatsoever for 14 months at the Public Utilities Commission. And I don't mean to single them out, because I think that somewhere between all of the different institutions involved in this, you end up with a pretty abrupt sense of failure.

We've been incurring congestion costs at the Miguel substation something on the order of

$3- to $4-million a month. Doesn't take very many months to erase that $31 million cost of the project in terms of foregone economic generation. The estimate I saw recently for an annualized number was 55 million.

So you'd add that on top of the congestion costs, as well, and you start to see that this is a project that economically pays for itself pretty quickly.

Now, as some of you know, the Energy Commission Staff revised its forecast last week for prospects for this summer. And I would anticipate that if we do indeed have a problem meeting our supply/demand balances this summer the problem is quite likely to be in southern California. And quite likely our failure to have approved these upgrades will play a fundamental role in that problem.

My friends at TURN, who I think are true connoisseurs of regulatory processes, described this particular project and the way the state has treated it as a regulatory atrocity.

So I don't think the process works now. I don't think we could get as much attendance at these workshops if the process worked. And I don't mean to single out your comment, because I think you were referring to something different.

But I don't want anybody to leave the room thinking that we don't have a severe process problem as it relates to planning for and permitting these transmission upgrades.

MS. THOMAS: I believe, Commissioner, that you're referring to more of a regulatory implementation than permitting issue more than a planning issue. Because the planning issue, it's no question that Mission Miguel was needed. And it was a correct decision. So you can't blame the planners.

PRESIDING MEMBER GEESMAN: I just needed to get that off my chest.

(Laughter.)

MR. ETO: All right, let's continue. Maury Kruth with the Transmission Agency of Northern California.

MR. KRUTH: Thank you, Commissioners. I'm Maury Kruth; I'm the Executive Director of the Transmission Agency of Northern California or TANC, as we're usually called. TANC is an owner of one of the intertie lines, a majority owner. And we jointly operate that with Western. We've worked with PG&E a lot.

I think I agree with part of what you're saying, but I also agree with Commissioner Geesman in that I think our planners generally do quite well at working with each other in various forums.

I think the doing of transmission, accomplishing transmission is where we have the real problem. And if you think back in some of the areas where I know Commissioner Geesman and Commissioner Boyd and I have had experience, Path 15 is a good example. It shouldn't have taken us as long as it did to get that accomplished. But we finally did.

The munis see transmission, who are my members, as a very important part of an overall portfolio. I mean we're not certainly -- my members are very active, as Ed Smeloff knows, in renewables, distributed gen, conservation. Certainly that's a cornerstone of every one of their resource plans.

But transmission is another piece of that equation. And the one thing I would point out that I think a couple of the presenters have commented on, transmission can be complimentary to those things. It can be used to deliver wind. It can be used to cover problems in the system.

Typically what we've seen on the intertie to the Northwest is it works in both directions. When California's surplus in the winter, on occasion, we can sell power to the Northwest. We can do things with the Northwest and with the system in Canada that really add value to California.

So, I would encourage the Commission to hang in there with transmission even though it's very difficult. I think we need an important robust infrastructure. We ought not be viewing either or, just transmission or renewables. We need both. And we need a robust system going forward.

MR. ETO: Thank you. Next we'll hear from Dan Ozenne from -- Ozenne, excuse me, from San Diego Gas and Electric.

MR. OZENNE: I'd like to thank Commissioner Geesman for giving my thought --

(Laughter.)

MR. OZENNE: I was going to mention the Miguel Mission problem that we have in San Diego. But I also wanted to touch on some of the alternatives to Maury's comments.

Because we in San Diego have been following the loading orders set out in the energy action plan and have really embraced that in our long-term resource planning. And that loading order has us consider all the alternatives that were discussed earlier today before we talked about generation and transmission.

So, the priorities of energy efficiency and renewables and so on are built into our long-term planning. So in terms of sort of when these things should be considered, they're considered very early on in our planning. Not late in the cycle. They're given ample opportunity for consideration.

And we believe that the answer to the questions that are being raised today is not the alternatives of either/or; it's not either alternatives or transmission, but both. Both are critically needed.

We have a growing population, growing loads. And some of that could be met with low-cost resources in our service territory. But we also need access to resources beyond our service territory.

As Commissioner Geesman pointed out, the failure to come to grips with the transmission problems at Miguel are costing, according to the ISO estimate for first quarter this year, $15 billion to San Diego customers. Doesn't take very long to build that line at that kind of price.

That's not really the full story. The redispatch that's occurring as a result of that are causing more inefficient, more polluting plants to be incremented to make up the difference. So we're burning resources that we don't need to at a cost that's higher than we need and polluting our environment.

We must deal with this need for additional transmission today. Steve mentioned sort of the energy action plan as a good plan for resources, but it doesn't say much about the transmission side. We agree with that. That more is needed in terms of making sure that transmission is available.

Including anticipating the needs of the future and identifying and preserving transmission corridors. And developing the reasonable and timely permitting process to make sure that those are available to us.

In the meantime we're aggressively

pursuing local alternatives; pursuing energy efficiency and demand response opportunities in our service area. We're about to go out with a request for proposals for renewable energy resources to meet our RPS targets. An objective, by the way, which we're not likely to be able to meet without new high voltage transmission capable of bringing wind and geothermal into our area.

Unfortunately, San Diego is located in an area where there's not a tremendous amount of opportunity for additional renewables. Our last renewable solicitation we contracted with every proposed project that was located within San Diego County and that met the market referent price.

And we'll continue to seek out those local renewable options. It's clear that we'll be required to import a good deal of the resources necessary to meet our goals.

In addition to these outreach efforts for renewables, SDG&E is pioneering the development of distributed generation within our service territory through our sustainable communities projects. These projects feature the integration of renewable generation and fuel cells at the distribution system level.

In our MarVista project near downtown San Diego we've worked with the developer on a redevelopment project that will include solar photovoltaics, an onsite fuel cell in a mixed use subdivision.

In another project we're working with a commercial tenant to include PV, fuel cell and advanced building design features in the redesign of existing commercial space.

We will continue to innovate with different developers and customers to explore new ways to integrate local power generation with our distribution grid.

In sum, we believe it's not either/or, but both. Transmission needs are real and immediate. And we're concerned that as early as 2006 reliability can become a major issue in San Diego unless action is taken very quickly to relieve our transmission congestion problems.

Unnecessary energy costs are already imposed on our customers due to the inadequate transmission. California must immediately confront its apparent unwillingness to expeditiously site and approve transmission necessary to meet reliability, least cost and renewable generation objectives.

Thank you.

MR. ETO: Thank you. Next we'll hear from Patricia Arons from Southern California Edison.

MS. ARONS: There's a lot I've heard today that I have agreement with; and a few things I don't fully agree. But let me make one observation.

I'm surprised that no one has come up with the idea that by getting rid of all the transmission planners you can eliminate transmission.

(Laughter.)

MS. ARONS: You might think that's funny, but in fact it's true. It's an option for how we're going to serve load in the future. And I've said it in hearings before that I view transmission as a societal choice. It's not just a transmission planner's tool.

But it's a decision that we all make. It's a very difficult decision to build transmission, but you have to have a company that's fully committed to do so; you have to have a regulator that's fully committed and behind the decision; and you have to have processes that have been adequately attentive to the issue of alternatives.

How do you go about considering alternatives, I think, is the critical question. You have to understand, in my view, what transmission is as a solution. If you think in terms of appropriate technology precepts, appropriate technology says you have an appropriate technological solution in terms of consumption of natural resources; in terms of consumption of capital; in terms of consumption of human time.

And what we've seen in California of late, I think, is that transmission, and in fact, has become an inappropriate technology solution because of all the problems and holdups and analysis paralysis that has resulted in transmission projects not being built.

And my concern is if we want to keep transmission as an option for the future, in terms of how we serve load, in terms of how we serve society's needs, I think we need to be more careful about thinking through how do we go about making the decision.

I agree that the process isn't as effective as it could be. I just don't have all the answers in terms of how to make it perfect. It's not a perfect process. It's very time consuming. Transmission is a very long lead time undertaking. If you think about the permitting process, the construction time, the decisionmaking time, it's a very long lead time undertaking.

In the course of a permit application, to try to consider alternatives such as demand side management and others, I think my concern is that those considerations really lead you down a path of analysis paralysis.

Options like demand side management, development of renewable generation, those are initiatives, in my view, that have to be made, decisions have to be made early on in terms of commitments, society's commitments to those particular technology solutions.

And I think the Commission's order, as described by Barbara Hale, is very effective in terms of making sure you consider demand side management and renewable development and others before you get to the question of alternatives, transmission alternatives.

We look at transmission being driven really by one thing, and that's the load growth impact on the performance of the power grid. Built into that load growth forecast should be the decisions that society has made at the outset on what we're going to do with DG, what we're going to do with demand side management and so forth.

I think also if you have an alternative that you're going to count on, you have to have absolute certainty of its effectiveness and success. You cannot rely on generation if, as we have seen of late in the ISO-controlled grid, that their retirements and shutdown decisions are a decision solely based upon the economic financial situation of the owner of that asset.

So, continued reliance on a solution that might have a very short-lived effectiveness is, in essence, just postponing the decision to build transmission.

There are a couple of things that were said this morning that I would like to reflect some disagreement with. Mr. Karras, I think, had said something about re-engineering the grid in order to be able to interconnect distributed generation resources. I don't understand that statement when your stated problem is a policy problem.

In my view there are protocols for interconnecting generation that are very well established. They're exercised every day by numerous entities looking at the potential for interconnection. We go through those studies at the transmission and distribution levels, in my view, very effectively. I haven't seen a complaint about generation interconnection come up in quite awhile at FERC.

I think the question comes down to is there a subsidy question in order to get generation -- I'm sorry, distributed generation off the ground. Well, that's a whole different question. That doesn't have anything to do, in my mind, with how the grid is engineered. So I just wanted to go on record with that.

I think the other thing that I would reflect is a comment from Mr. Smeloff from the San Francisco Public Utilities Commission. And that first of all let me compliment you. I think you guys are doing a great job in making societal types of choices as alternatives to transmission. But I want to chastise you for putting up a circuit diagram and handing it out, and in a presentation that's going to be, in essence, posted on the internet. And what the transmission map put up is basically it's going to inform the uninformed about the vulnerabilities to the electric service to the City of San Francisco.

I think anyone can look at that and decide that the vulnerable points, if they're so inclined to attack, are obvious on that map. So I would be very concerned about not treating critical electrical infrastructure assets as a matter of security for the City. And I think the PUC should review its policies in that regard.

With that, I think that's my comments today.

MR. ETO: All right, next we'll hear from Armie Perez from the California Independent System Operator.

MR. PEREZ: Well, actually, I already made my presentation, so you know where I stand. But I do have a couple of questions, and I think you just did one. One was for Greg, and I really was trying to figure out what you meant by redesigning the grid. Because if, in fact, distributed generation takes on and demand side takes on, what's going to happen is at my level I'm going to be seeing a load equalization or a load reduction.

Which would mean that at some point in time I'm going to say, well, by seeing what's happening say in the City and County of San Francisco, I'm basically going to say I'm going to fire one engineer. I don't need any more resources out there. That's a stable condition that's going down.

Actually, it may start me thinking, going back to John's question, I now may have a white elephant, I may have a transmission line I don't need, which I'm going to have to bring down. Just think about that and we can talk it some other time.

The other question I had was for Mr. Kelly. I was somewhat intrigued by the statement that you made that you need more transparency in transmission planning. And I was trying to figure out with all the transparency I'm giving you right now, what else do you need? What am I not doing right, sir?

MR. KELLY: Well, I think I put things more of a political context, because if the lack of transmission infrastructure is not stemming from the engineers and planning assistant at the bottom of the tier, it's stemming from the problems that occur in the political context where people are not convinced that there's a need for the project, or they've convinced policymakers that they've got a way to litigate against the project being built.

And when I talk about transparency I'm talking about a process so that when the PUC or the Energy Commission or whoever it is comes out and says, we've looked at the alternatives and we believe that this project is the best alternative and it should go. Then the other agencies are relatively quiet on it, and it's harder for people to litigate to stop it.

I don't think we have that kind of comfort in the planning process to the final decision. And I didn't mean to be talking about all the engineers, the 15 or 25 in the state that actually might know what's going on, that are plugging modeling and inputs in and out. I'm talking about a higher level of transparency.

MR. PEREZ: Okay. The other two points I wanted to make is we still have a problem with generation. For example, I believe that Otay Mesa generation was approved last week. I also believe, correct me if I'm wrong, that only the connecting line between the station and the grid was approved. So now we have another plant that's not going to be deliverable until something else happens, because it's going into the wrong area of the system.

We keep making those decisions, and then we worry later about why we're spending so much money.

And finally, I want to agree with Pat, I think she had a very keen insight into the idea of we're responding -- I am responding to society's choices. Society decided to build a plant in Mexico, 1600 megawatts of it or so. I don't know why, but that's where they put it. And there's some economic advantages created by that plant being there.

At the same time we have about 4000 or 5000 megawatts of generation has been added outside of Phoenix. If you consider that the entire load of the state is about 4000 or 5000 megawatts then you realize that there has to be a lot of generation that's looking for a place to go. And guess what, folks, we are the black hole of the WECC. They all want to come here and they are making very good deals to get it here.

So, we are responding to where the economic opportunities are, and I'm afraid that unless somebody tells me otherwise, I have to keep looking at what's the best. The question is do we want 4000 or 5000 megawatts in Arizona, and -- 4000 megawatts in here. Do we build a transmission line? What do we do? Those are the challenges that I have to deal with every day. Thanks.

MR. ETO: Thank you. Next we'll hear from Barbara Hale from the California Public Utilities Commission.

MS. HALE: Thank you. Like Armie, you already heard a lot of my comments in my earlier presentation, but, Armie, just building on what you just described, I would commend to you all again the staff report attached to our transmission permit streamlining rulemaking where we talk about this very problem of transmission chasing around generation.

Merchant generators have economic incentives to place plants where it makes sense for them. Doesn't necessarily make sense for the grid. Doesn't necessarily make sense for where the load is.

And I think there are some market design changes that will help. There are some permit streamlining change -- at the ISO -- there are some permit streamlining changes at the Public Utilities Commission that will help. But as we get more and more into a disaggregated system where folks like the City and County of San Francisco are going to embark upon a community choice aggregation program potentially, we're going to see another group of interests operating outside the venues we're comfortable with, or familiar with -- not comfortable -- where, you know, a large group of PG&E customers will have a different venue to go to, to demonstrate load and need.

That's going to have to be integrated somehow into the actual operating system that Armie's challenged with on a daily basis.

But let me go back to the how, where and when question. I mean I think that's a broader challenge for us to bear in mind.

I talked before about the how, where and when question. I think the how is through an integrated iterative process. We're going to have to look at balancing of portfolio of resources. And in an iterative way look at what the resource options are and what makes sense, given the public policy pronouncements from Sacramento and from within the various state agencies, like the energy action plan.

Where, I think that's basically a question of following the dollars. The where for me is at the decisionmaking authority's designated venue where the investment authority lies. That's where you need to look at making the final decision on what resource alternatives should be invested in.

And in terms of when should alternatives be assessed, I think it's a two-step process, as I described before. Prior to permitting at the Public Utilities Commission, prior to any permitting we're looking through the procurement proceeding at all the resource options. We're looking expansively at alternatives in a planning forum prior to permitting. When a CPCN comes to us, that permitting effort, where we've got a specific project, that's when the alternatives are narrowed. And I think it's appropriately narrowed.

If you've looked at the broader issues and the broader choices and overlaid the societal preferences that we see from our lawmakers and from things like the energy action plan, that should happen in the planning stage.

Then when you're going through the CEQA process you've got a specific project, a specific need that you're addressing. And it should be a more narrow analysis.

And so I think the when you look at alternatives is two steps. Planning and permitting.

And then I'd like to talk just a little bit about how I think the CEC can help in this kind of an environment that I've just described. I think the IEPR assessment authority that the Energy Commission has is very broad and very constructive in aiding entities like the Public Utilities Commission, like the IOUs, like the munis in looking at resource options.

The demand forecast effort that is pursued through the IEPR is very constructive for the PUC. We are relying on it as the basecase for the investor-owned utilities' assessments of their needs.

The statewide assessment of available resources is also very constructive that comes out of the IEPR, predicting, for example, retirements. The study you folks are pursuing there is very constructive for the sort of planning and procurement effort I've just described.

Anticipating resource needs and conducting focus studies like the corridor planning we've talked about earlier today; like LNG prospects and defining the public interest on LNG, which is a big future fuel for electric generation. Looking at renewable resource availability as you did pursuant to the RPS statutes.

The impact of intermittent resource development on grid reliability is an area that I think the Energy Commission can pursue in its IEPR, under its IEPR authority that would be very constructive for all of the entities who have to make some of these investment decisions.

And I would just encourage the Energy Commission to look at its IEPR authority in its statewide role and try to bring more interests together, and try to focus on all of the load-serving entities' responsibilities. Because I think ultimately we're all going to need to work together to have the systems maintain reliability while we go down a road, I think, in California, that has a much more disaggregated load and supply set of options and responsible authorities.

Thank you.

MR. ETO: Next we'll hear from Ed Smeloff from the San Francisco Public Utilities Commission.

MR. SMELOFF: A couple of comments. The first comment is on the issue of interconnection of the distributed generation. While the rules are clear, rule 21 is clear for connecting distributed generation to radial feeders, the rules are far from clear and the experience of developers in San Francisco has been very complicated when you're connecting to a network system.

And it was even our own experience with the Moscone project, which was connected, a solar, 670 kilowatt solar project, connected to a spot -- work system where it wasn't revealed to us what the additional costs of doing that, in terms of system protection, was until we were well into that project.

So there is, I think, a need for some more transparency and clear rules related to interconnection in network systems.

Let me also comment about this issue, the tradeoff, the balancing between security, which obviously is a great societal concern, and transparency in public participation. In planning for the system in San Francisco we've had a very involved community stakeholder process that did involve the ISO and PG&E, including some detailed power flow analysis.

And it was only through that kind of analysis that did involve the community that very specific projects came up. For instance, as Mr. Karras mentioned, the need for some additional reinforcement of the internal 115 kV system in San Francisco.

And the choice of what those alternatives could only be done through revealing to those people who were participating, you know, how the system is designed. Even getting down to some operational details; looking at how the system clearances are done in one of our substations in San Mateo, needed to be discussed publicly so that alternatives could be understood by the public.

So there is a balance. I agree that you don't want to reveal too much detail of information that certainly can get into the public domain, but it needs to be balanced with a need to work with your public to adequately evaluate alternatives.

This whole issue of timing, I think, is really a crucial issue on how we look at alternatives. I think the permitting process really is too late of a period of time to adequately consider the smaller scale resources, distributed generation and DSM, that would require many actors to implement them. Such as in the case of Jefferson-Martin, that was really not an appropriate time to think of, well, alternatives to Jefferson-Martin could involve very aggressive energy efficiency or DSM.

But I want to say that having a public participation process in advance that looks at alternatives, I think, can result in more support and certainty that once a transmission project is agreed to, that it will get through the permit process and will get built.

So there is a need, I think, far enough in advance for us to look at what are the potential distributed generation and DSM alternatives. The details, I don't know the details; how far in advance, five years. Gets to some of the issues I discussed about understanding load growth, understanding specific locations where, down to distribution lines where load growth is going to occur.

Having some new planning tools, new ways of analyzing that, I think, will aid us in the process of looking at alternatives. But we do need to think pretty far in advance as we look at alternatives so it doesn't delay those transmission projects that turn out to be genuinely needed and need public support.

MR. ETO: Okay, thank you. And now we'll hear from Greg Karras, Communities for a Better Environment.

MR. KARRAS: How should alternatives be assessed. Like this, I mean my perception of today, I threw an alternative into the mix. Well, a lot of you listened to me. I wasn't sure that was going to happen. Mr. Perez, you acknowledged that you heard me. You said, as understand it, you'd think about it. You raised some further issues for me to think about. You invited further discussion like this.

Compared to like getting to the point where people feel rushed and they've got to finish their paperwork and they come up with the equivalent of, well, do you want a choice between a donkey and a horsecart, when in fact there's an automobile out there. You know what I mean?

I mean I don't think you are disagreeing that if you had a clean sheet of paper and were told to design a system to serve a solar panel on every house, that you'd build the one you got now. So, like this.

When -- I mean, to avoid saying over lunch I'll say, whenever a good idea comes up it needs to be looked at, you know. We can't necessarily control the creative process or the way technology moves. It would be stupid to try to pretend we could. I think when a good idea comes up you look at it.

Where, you know, again for us this is an issue of social and environmental justice where the people who have the most risk of the biggest impacts live. If you're talking about where I live and where we've been working, come to southeast San Francisco, in the community with the community, after working people's hours in the evening. If you're talking about a different place, well, whatever works there.

But I mean, you know, I just want to be really specific about it. I heard a lot directly and indirectly about, you know, concerns, it's hard to permit things and get them through the process, and it's frustrating. And sometimes projects get delayed. Well, you know, from our perspective the reason why projects get delayed is the community doesn't know what's going on, or it feels like people have been hiding the ball.

And the way to fix that is largely by answering the where question. By doing what the community that's most impacted, and doing it there.

That's it.

MR. ETO: Okay, thank you. Before I turn it back to the Commissioners, I'd like to ask if there are other interested parties or individuals that would like to comment at this time.

Please identify yourself for the --

MR. MOBASHERI: Fred Mobasheri.

MR. ETO: Why don't you come here and speak in the mike. Fred, come over here.

MR. MOBASHERI: I'm Fred Mobasheri from Electric Power Group. We have done three studies for the CEC. The first one was on the value of the transmission, when we showed that most of -- all the transmission that had been built in California were cost effective and they have brought a lot of benefit.

The second question is when do you do these alternative evaluations. And Barbara suggested that long-term procurement is going to take care of these alternatives evaluations. My concern is that it's not real long term; it's going to be mostly five to ten years maximum.

The emphasis in the utilities is going to be what's the next resource they want to build; what's the next transmission they want to build. And that's not really looking at the very long term.

Discussion here has been that most transmission takes 10, 20 years to build. You have to look at very long term. And I doubt that the procurement planning that they're going to present to you at the PUC will take care of the strategic questions.

If we are really looking at the strategic questions such as corridors, land acquisitions for the new transmission in the future, I don't think the long-term resource planning is going to answer those type of questions.

Then the question is what do you need. In my opinion you really need strategic planning. And that's not being done right now. It's not been done in the long-term planning, and it definitely is not done when you are looking at specific projects. And perhaps something like PUC or CEC or maybe Cal-ISO should do the strategic planning.

The problem with Cal-ISO is that they're going to look at only transmission, not the other alternatives. And so perhaps the CEC should be really looking at the strategic long-term questions that nobody at the present time is looking.

Thank you.

MR. ETO: Thank you. Is there any other

public comment from other interested parties or individuals?

With that, let me turn it back to the Commissioners to conclude.

PRESIDING MEMBER GEESMAN: Well, I think we're going to get into some of the questions that Fred raised after lunch. And probably the best way to leave that is just to invite people to come back in the afternoon because I do think we're going to spend a fair amount of time on what is the appropriate time horizon and how should we be calculating strategic benefits, and how do they translate to people that live here now and pay electricity rates now.

I want to thank each of you for participating this morning. I found it very illuminating, and I think that as we sift through the record that we've developed in this series of workshops, we're going to have a fair amount to ponder.

I expect that the staff white paper that we come out with as our next step may be fairly provocative to some of you. And I'm certainly hopeful that if it is provocative that we certainly hear your unfettered feedback and reactions to it.

Commissioner Boyd.

COMMISSIONER BOYD: Real quick, for fear that some people won't come back after lunch.

(Laughter.)

COMMISSIONER BOYD: The last gentleman really did touch on some of my concerns. The broader look, more strategic planning and what-have-you. And I know we're struggling with that. And I do look forward to more discussion about that.

Not meaning to pick on Barbara Hale, my old friend, but in the dialogue about -- I just want to use an example, you mentioned the San Francisco regional planning effort, and kind of like, oh, my gosh, another planning effort. And on a microscale rather than a macroscale.

And I will confess, some time ago, being newer in this business, to be concerned about the San Diego regional planning effort, the San Francisco regional planning effort, as we're struggling to figure out what the whole state is. And that's kind of an academic reaction. Maybe much like Barbara's.

But, over time the inability of all of

us to gather everything under one tent and discuss all the aspects, as you would do in a strategic planning effort, and addressing some of my pet peeves about local land use planning, or looking far enough down the horizon, I've come to accept and even almost look forward to the contribution of some of the local efforts that are going on. Because I'm hopeful that they will look at more of the issues than heretofore we seemed to be able to look at.

And it's been mentioned here that some people, you know, really are under charter, under legislative mandate to look at certain pieces of the puzzle. And I think for the first time a lot of us, in view the energy action plan, things like that, have recognized the need to look at a broader picture.

I think we're still struggling with that, and I hope all these puzzle pieces will come together some day so we can salvage this situation before there are 50 million people in California and no ability to put anything anywhere because everything would be in somebody's back yard literally.

But we do need desperately to do some

long-range planning. So I look forward to this continuing discussion. And I wasn't picking on you, Barbara, I was just using that as an example.

MS. HALE: And I didn't feel picked on. But I'm pretty thick-skinned.

If I could just comment, though, on one thing that you said and that Mr. Mobasheri said. And that is I don't mean to be suggesting that the effort of, for example, the City and County of San Francisco is a sign of foreboding, a bad thing. But rather -- no value judgment there, but rather it's a reality that we're going to have additional load-serving entities.

You know, right now the focus of today has largely been what are the investor-owned utilities doing with transmission and how are you integrating it. I mean, I think that's what we're hearing a lot about. We did hear from LADWP; we did hear from a representative of TANC. But I mean largely what you folks have spent your morning on, and given this agenda, is investor-owned utility issues, the load-serving entity issues.

But that list of load-serving entities is going to grow just by the fact of the way the law was written for community choice aggregation; the efforts at implementing a core/noncore program. So I think it's just -- I just mention it because it's going to get more challenging to do the kind of strategic planning folks are saying the state needs.

By way of Mr. Mobasheri's comments I don't think we disagree. I see the investor-owned utilities' long-term plans as being, you know, long-term plans, 20-year plans. The actual investments that will happen as a result are going to be meet near-term needs, the five- to ten-year needs.

And I intended in my comments to call out where I thought the Energy Commission could put some real added value in, which are on some of those longer term strategic planning issues like corridor right-of-way issues, corridor planning.

So I really think it's leveraging each other's authorities and expertise to get to where we all want to be. Thanks.

PRESIDING MEMBER GEESMAN: Why don't we come back at ten minutes to two.

(Whereupon, at 12:48 p.m., the workshop was adjourned, to reconvene at 1:50

p.m., this same day.)

AFTERNOON SESSION

2:01 p.m.

MR. KONDOLEON: Good afternoon. We'll be beginning our afternoon session with a small change in the agenda. We're going to have a staff update on the development of the transmission vision for California provided by Judy Grau.

MS. GRAU: Thank you, Don.

Okay, I hope you all had an opportunity to pick up the afternoon handouts. I have two handouts for this presentation. One is my PowerPoint presentation, itself; and the other is a one-pager called draft vision statement June 14, 2004. I will be referring to the vision statement later in my presentation.

Okay, I have five things to talk about this afternoon. First is the purpose, why we're doing this. Some background from the April 5th and May 10th workshops, transmission workshops. A summary of comments received since the May 10th workshop. The draft vision statement, itself. And then some suggested next steps.

So the purpose is to collaborate on the

development of a long-term vision for the state's transmission system. This is going back to the first workshop where we talked about this on April 5th.

The process began at that April 5th IEPR Committee workshop on transmission with a presentation by Joe Eto of CERTS on alternative scenarios of the state's transmission future. The Commission Staff, me, then gave a presentation on some of the drivers that influenced the development of a vision, the process it plans to undertake, and the next steps.

That was followed by a roundtable discussion with 19 participants. And that was followed by five parties submitting written comments following the workshop.

The Commission Staff then summarized all of the oral and written comments, and published these in a summary document in time for the next workshop on May 10th. That document was discussed in my presentation at the May 10th workshop where I described some of the common themes, the guiding principles and the short-term actions that emerged from the comments, and the next steps. And the website address is there if you have not already seen that summary of comments.

Specifically in my May 10th presentation I identified the following next steps. First, receive feedback from stakeholders on the accuracy and completeness of staff's summary of comments.

Second, receive feedback on the relative importance of the themes and principles which I laid out. And third, receive feedback on the three specific short-term actions which were first to initiate corridor planning; second, to investigate land use banking; and third, to continue efforts to demonstrate and deploy technologies that allow the existing system to be used more efficiently.

And then the fourth thing was to present the results at the next workshop, which we are here today for.

So, we didn't receive any oral comments at that May 10th workshop. I was last, it was late in the day, I know everyone was tired. However, we did receive three sets of written comments after the workshop from Donald Clary of the Pechanga Bank of Luise¤o Mission Indians; from Robert Sullivan of Mammoth Pacific; and Bernie Orozco of Sempra.

And the next four slides summarize those written comments which we received. First, the Native American Tribes must be an important part of any transmission planning process, especially because of the both renewable and nonrenewable resources located on tribal land in the state; and any transmission vision must expressly address and encourage this participation.

Tribal concerns regarding sovereignty and historical and cultural resources must be dealt with more than just superficially. Tribes need to be compensated appropriate for rights-of-way and easements.

The vision must encourage development through an inclusive process that provides assurance to tribes and others that their reasonable concerns will be addressed in the permitting process.

Actual project plans must accommodate energy needs on impacted reservations. Transmission is only one of the many planning considerations that communities face. Tribes and others may need to have resources provided to them in the transmission planning process, so that their adequate participation can be assured.

We need to consider the impact of aging and inefficient existing lines that limit access to renewables, contribute to line losses, and have high maintenance requirements. An example of this provided by Robert Sullivan is Path 60. He said that renewable energy originating from Mono County is limited by two aging and inefficient Southern California Edison lines, 115 kV lines between the control substation in Bishop and Inyo-Kern.

We need to insure access to an optimum mix of long-term energy resources for California, including energy imports from outside the state. Planning ahead for corridors and setting aside right-of-ways and appropriate action to provide guidance for long-term transmission planning.

We need to accommodate the possibility of corridors through federal lands. And finally, the state agencies need to work together to expedite the transmission licensing process.

And so given all of the input received today, the staff developed the following draft vision statement. It's the vision for the State of California to have a bulk transmission system that is planned, permitted, constructed and operated in a manner that effectively balances the needs for a safe, reliable, cost effective and environmentally sensitive electricity system.

That's a pretty tall order. And so what I did on the following slide is take -- that is sort of the motherhood-and-apple-pie statement, but to make it more practical, broke it down into some of the elements that should go into the development of the vision. So that's what's on the next slide.

So, first, it should be coordinated with and effectively consider the needs of California's residential, commercial and industrial customers. By the way, these are not in any prioritization order. You'll see that on the next slide. I would like to get feedback from people on should we prioritize, or can we even prioritize. So I'm going to list them, there's eight items, but these are not necessarily prioritized.

The second item is should be coordinated with and effectively consider the needs of local agencies, jurisdictions and sovereignties. We heard from several people this morning, Greg Karras and others, about the importance of following local communities' advice.

Third, it encourages continuing

beneficial interchanges with California's neighbors.

Fourth, it allows for the implementation of a portfolio approach to solving California's electricity requirements while contributing to a sustainable electricity future. With respect to the portfolio approach we heard Armie Perez express his frustration at the fact that he doesn't have all of the transmission generation and energy efficiency tools available to him to do such a portfolio approach at the moment.

And Dan Ozenne of San Diego Gas and Electric, and also I think Patricia Arons mentioned the importance of a portfolio approach, too. And we also heard from Greg Karras about the importance of contributing to a sustainable electricity future.

The fifth item, the vision should value strategic benefits when considering system upgrades, including the ability to respond to unpredictable future conditions. With respect to unpredictable future conditions, Greg Karras mentioned the possible climate change impacts. And with respect to strategic benefits, Armie Perez mentioned the insurance value, and the fact that we don't have any white elephant transmission projects. So you never know what you build today, how it's value will be perceived in the future.

The sixth item, it encourages making low-cost investments now in order to preserve opportunities in the future, especially with respect to corridor planning and set-aside. We heard from Susan Lee this morning about the importance of that.

Seventh, the vision should encourage continuous developments through investments in transmission R&D, both hardware and software. Barbara Hale this morning mentioned that between the IEPR process and the procurement process we need to continually iterate on the resource plans to consider, among other things, new technologies that become available.

And finally, the vision should promote the application of the Garamendi siting principles to maximize efficient use of the existing system. And the Garamendi siting principles are analogous to the state energy action plan's loading order. And they are, for transmission, though, and first to encourage use of existing rights-of-way; second, to encourage expansion of existing right-of-way; third, to provide for the creation of new rights-of-way; and fourth, when new transmission capacity is needed, to seek agreement among all interested parties on the efficient use of that capacity.

And so as next steps, we'd like to get feedback from interested parties either this afternoon or -- let's see, the comment period goes to June 25th, so we would like comments anytime up through then, on these following questions:

First, does the vision statement and its elements provide the proper guidance to policymakers in choosing the future direction of California's transmission system?

Second, is it complete? Are there other elements that should be considered?

Third, should the elements be prioritized? And, if so, how?

And fourth, how do we implement the vision?

So that's it for my presentation. Any questions?

UNIDENTIFIED SPEAKER: You said you wanted comments by the 26th?

MS. GRAU: The 25th. Friday, the 25th.

MR. KONDOLEON: Thanks, Judy. And, again, I'd like to encourage folks to provide comments to us. As Judy pointed out, we'd only received three sets of written comments from the last workshop. So, we know there are lots of folks out there, and we're trying to put a consensus into this development of a vision statement.

So, again, I would encourage you to read what we've put together, and to provide comments if you can by the 25th of June so that we can reflect that in our document that we'll be releasing the latter part of July.

Moving on, we're going to be now discussing the valuation of strategic benefits of transmission interconnection. The initial presentation will be from the California Independent System Operator, discussing the transmission economic assessment methodology. And Anjali Sheffrin is going to lead off that presentation.

MS. SHEFFRIN: Good afternoon. It's a pleasure to be here. Thank you for inviting us.

What I'd like to do for you today is review the methodology for assessing transmission expansion based on economic need that the ISO is proposing. What I'd like to go over is what the status of this methodology is now; why we believe it's valuable and can be applied today. I also will talk about its overarching goals, what we tried to accomplish in developing this methodology.

After myself, I have the lead researcher on this project, who will discuss with you some of the more specific aspects of how we went about modeling, the modeling effort that was contained in this project.

So the first question is, why did we develop this methodology. I think we can answer that by looking at the situation that we faced. There really hadn't been a major transmission line that had been added in the last 15 to 20 years. We thought part of that was due to a lack of consensus on how to determine economic benefits and how to assign those benefits to different participants.

Really, our effort on this team methodology came about when the ISO recommended the upgrade to Path 15; and when we went before the CPUC and found how difficult it was to really justify all the parties. We came back and said, you know what, we really need a standard way, a standard way to talk about these things, a standard method, a standard database, all of those will tremendously help the effort.

The second reason -- and so, you know, we saw in the Path 15 effort, really a lack of consensus on how to assess economic benefits. Every party had a different way of talking about it.

The third was obviously lack of regulatory predictability on economic need determination. We feel that if parties know how it's going to be evaluated that that'll help streamline the whole effort.

And in putting this methodology forward we realize that there's a lot of noneconomic factors; economics is not the whole thing. And so we definitely do agree that noneconomic factors have to come into the decisionmaking right at the right-of-way issues. Environmental costs are very difficult, but to the extent that they can be quantified, we feel our methodology allows that.

And then, of course, other concerns about getting a transmission line together. And that's the different multiparty agreements that may have to be accomplished before a line is sited.

So the overall efforts of the TEAM effort was to get a common methodology to evaluate the need for transmission upgrades that, you know, everybody could use; project proponents; the ISO; different regulatory agencies. And we wanted this methodology to be as transparent as possible so when people were looking at perhaps proposing something they would know ahead of time how this was going to be evaluated.

We believe the framework we've presented can be used today; not something that needs further research. We feel that we've done the research and have a transmission methodology, evaluation methodology that can be applied today.

The other big effort for this TEAM effort was to provide transparency, both in the methods, the databases and the models. And we feel that we have accomplished that. We filed this methodology with the CPUC. Part of their proceeding does require us to make the methods fully available and documented. And I've given you a documentation of our TEAM methodology.

The databases, we worked very hard to get a standard database of WECC, which we got from PacifiCorp. And we worked with them to make sure it's available to anyone who asks for it at no cost. And that is now available to people.

And then in terms of the models we were careful in choosing model because we understand that these models are both very expensive and high maintenance. We tried to choose one that's fairly well documented. You can download it off the web. It comes at a fairly economic price compared to the others. And given the small number of staff that I had to run it, I can attest that you don't need an army of people to run such models.

I think a lot of people here are familiar with the public process we went through, but just to give you an overview, it's here for your reference. Let me quickly review it.

In February 2003 the ISO filed a general blueprint for an economic methodology to evaluate transmission. We held a public workshop March 14th at PG&E in which everyone was invited. And we went through in great detail that methodology.

After we had filed it with the CPUC there was some concerns as to whether a tool was readily available to apply this methodology. The ALJ at that time said, you know what, everyone says a network model representation is important, that's not what you filed with us. Why don't you go back and work on the full tools that would be necessary to apply this methodology.

And in December of 2003 the CPUC ALJ said, okay, time's up. You should have been working on this. Go ahead and file what I call not just the blueprint, but, you know, the whole house built, constructed, so we can do a walk-through. So we then did start making sure our models, our databases, all of those things, were ready to be filed.

We held in early 2004 three public workshops. We has 12 technical calls. We also solicited input from the market surveillance committee. That's an independent committee to our board of directors made up of four academics. And going before them is -- I always feel like I'm defending my thesis all over again. But, they have written an opinion on our methodology. I believe that is with you, as well.

We filed the methodology on June 2nd with the CPUC. And our understanding is that there will be hearings on this over the summer and fall of 2004.

So let me just review at a high level what are the major contributions that we feel TEAM accomplished. First, we did develop a consistent method to identify benefits to all parties.

Second, we incorporated a process to reflect the fact that prices in the market reflect bids, they do not reflect costs.

Third, we actually put together an algorithm of how do you put in dynamic bidding strategy of different players in a network model.

The other area that has been talked about this morning is how important it is to find out future uncertainty, and how do you incorporate that into your investment decisions. So we feel we've really enhanced the field here with a method to compute expected benefits based on uncertain variables, as well as insurance value transmission. I don't think we've actually calculated the insurance value, but we've shown how that can be done and easily incorporated. In order to calculate insurance value obviously you have to survey the policymakers; find out their degree of risk aversion. That's not a step that we have done yet. But we certainly recommend that it be done.

The fourth area that we worked on is integrating generation transmission investment. You heard a lot this morning about what should go first. Should generation just decide to go wherever it needs, and transmission should go and chase it and make sure it's hooked up and deliverable to load. Or is it really the transmission should go first, and generation then needs to respond to the price signals. We tried to integrate really both of those decisions in what we think is a consistent manner.

And lastly, this isn't just theory, we actually showed how to implement this evaluation with an actual case, which is the Path 26 upgrade.

So when you think about the TEAM methodology you really should think of five main components. The benefits framework, a standard way to measure benefits separately for consumers, producers and transmission owners.

What we found is in the past when there were these arguments about who benefits and who doesn't, people weren't talking in a consistent manner. So we feel like we've offered that. And

I'll show you a little bit later how our benefit template looks. You can look at these benefits of an upgrade in a specific location, or as broad a region as the entire WECC.

The second element is market prices. As I said earlier, we utilized market prices rather than cost. Traditionally a lot of these transmission expansion studies have just said, well, people will bid their production cost. Well, I'm the Director of Market Analysis at the California ISO. I've been there for seven years. I watch the market; people do not bid their cost. So you definitely needed a methodology that reflected market pricing regime rather than cost bidding.

Third is uncertainty. We considered a wide range of impacts of future system conditions; dry hydro, gas prices, demand growth, over and under generation entry. All of those are critical and can impact the benefits that you calculate of a transmission line.

Fourth, network representation. I was surprised at actually how controversial this ended up to be. Our view if that you need to have a network representation that shows that the flows are physically feasible in a network model. What we found in the past really through bad experiences is you can use a transportation model but then you make assumptions, and in fact, things -- you haven't modeled the downstream constraints. And so even though you think things are deliverable, you end up with bottlenecks and things aren't. So we have stressed very much in this methodology that any study show that the flow is physically feasible.

And last, we did have resource substitution. Whenever you look at a transmission line, as you've heard this morning, you should look at what the alternative is. That is the best way to evaluate whether that's a cost effective decision or not.

The next question is should TEAM be accepted as a standard for transmission evaluation. Well, my belief is that it should be, for the following reasons: It is very complete. We have tried to document it to the best of our ability. It clearly indicates the impacts of a transmission upgrade, you know, at any level you may want to look at. And by various definition or participants, consumers are impacted in a region;

how producers are impacted; what happens to transmission owners' revenues.

And the third reason we think this is do-able, obviously, is that we demonstrated it in an actual study. So this is not high theory. The tools are available right now.

What are some valid applications of the TEAM methodology? Well, definitely for planning a specific project like Path 26. We also think it has a lot of value in terms of long-term strategic planning. The SG-WI effort identified a value of relieving congestion on major corridors throughout WECC under three resource strategies.

I think what we did is we took that database and then expanded it for the renewable criteria in California, a lot more detail that was necessary for California, revised it to the CEC's load forecast, all those things. So we definitely think SG-WI proved this is important for strategic planning and we tried to build upon that.

I think that this model can be used for strategic decisionmaking, to decide whether to build transmission, or whether some other means is more cost effective, renewable generation, demand side, all of those. And, of course, in this type of model you also can do the generation adequacy evaluation. You can look at either LOLP or LOLH or cost of unserved energy in any resource scenario you're looking at. It will tell you those things by region. And we think, of course, that's very important, as well.

Sorry for how busy this slide is. This gives you just an idea of the benefit templates and what I've been talking about. You can decide the perspective you look at, societal meaning all of WECC; modified societal; or go down to a specific region, ISO ratepayer; ISO participant.

And then you also can go across which we call the description of the benefits, is the benefits going to consumers in a particular region, producers, transmission owners and what's the total.

And what we've done in this study is we've built upon the traditional cost, production cost models, and made sure that we're consistent with that. So on a societal basis, you'll always see the equality of total benefits from this methodology and production cost savings.

And that simply says when you expand a line you want to know to what extent are you being able to serve all of load cheaper. So this is sort of what we call productive efficiency.

Then when you go down this column, this is what we call consumer efficiency. When you look at WECC-wide for all participants, this is counting monopoly rents as well. Our market surveillance committee said, well, you know, when you expand a line and it allows people to charge higher monopoly rents, or it lowers those monopoly rents, should you consider that as a cost or not. And they recommended that that not be considered a cost. So, that's what this modified societal is.

And as you can see on total benefits that goes up because you're not counting the loss and producer surplus associated with monopoly rents. You still have producer surplus associated with competitive rents, but not monopoly rents.

And then you can go from a WECC down to a say, ISO, California ISO perspective. And look at ISO ratepayer, which is just the consumers of the three IOUs, or ISO participant, which is both producers and consumers in the ISO system. And this is really the measure that we're advocating.

So, essentially what you're doing in this Path 26 upgrade is saying when you upgrade the path what happens. And why is it that California benefits more than WECC-wide. Well, the reason is Path 26, in essence, lets a lot of bottled generation that was built in the Midway-Vincent area, as well as in northern California, go down and meet the high load growth and high cost load in southern California.

As a result, what happens? Well, the Northwest producers sell a little bit less to California and the Southwest producers sell a little bit less to California. So when you look at California benefits, it is a multiple of, you know, the WECC benefits.

So this gives you just an idea of what type of things you can calculate using this methodology.

One of the things that we look at obviously is what are the variables that mattered the most in our evaluation. And this is just looking at single variables. And I just listed three, but we have much more. We have hydro conditions and how that affects the value of a transmission line.

But the one that mattered the most, of course, was market pricing. And as you can see from this chart, just one single variable impact on benefits went from zero to $25 million. That's a huge range in just one year. And you might say, really, can we believe this. Again, being the market monitor for the ISO, you can believe it. I watch how much things get bid above what I would consider competitive costs every day. And transmission lines gives you an insurance against that type, because it enlarges the market, it makes sure that more suppliers can come into an area and compete and keep costs up at a competitive level.

And these are just some of the other variables and their individual impacts. But what we did in the study is not look at individual variable impacts, but joint variable impacts. And this is the result of that. And this is just a histogram of all the benefits under all the scenarios that we ran. And I think we ran about 40 scenarios, you know, in bins of $5 million annually.

And essentially what you can see, say in this bin is annual benefits of $15- to $20-million as a result of expanding Path 26. It had a probability of about 16 percent, given all the variety of scenarios we looked at. And this was the expected value.

Now, Path 26 is a $100 million project, so about an annual cost of $10 million. So, from our study initially what we've come up with is the expected benefits do look worthwhile compared to the expected costs.

So our recommendation on this particular implementation was that an upgrade of Path 26 may be feasible. There are additional items that need to be checked. Definitely the capital costs have to be checked. When we asked the transmission planners, they just gave us a SWAG. You know, 100 million plus or minus 50 percent. Well, we'd appreciate that to be refined a little bit more, but our studies demonstrate it's worth going after to refine those capital costs.

We also, you know, the transmission planners say that there are some alternatives to Path 26 upgrade. We absolutely think that those should be reviewed.

In our study we did have the Palo Verde-Devers 2 line in, so we've already accounted for that benefit. But, you know, obviously you want to make sure that as you add lines your benefits aren't going in one direction or the other.

We also would recommend that you calculate the insurance value of risk aversion. Again, we had an expected benefit, but, you know, that's if you aren't risk averse. You may add $5-$6-million a year just because you are risk averse. We don't know what that number is. We do recommend that that be studied further and that be added.

To the extent that environmental costs are known, we would recommend that they be included in the study. And we were only able to do the study because of the short timeframe that we had. We only had like a four-month timeframe after we picked the model and got all the databases ready. But that additional years be run. Certainly 2018, because this is a long-life investment.

So with that as background I'm going to let Mingxia Zhang talk a little bit about this. But if you have any specific questions, I'm happy to answer them.

PRESIDING MEMBER GEESMAN: I do. How far out did you run your case. You said you want to do a 2018 run, but how far out did you go?

MS. SHEFFRIN: As I said, we only did two years. We did a 2008 case and a 2013 case. And we tried to put in all of the information working with your staff, as well as the CPUC Staff and members of the public.

The renewable portfolio standard is in there, as well a the load forecast. Not your newest load forecast, the one that was published December of 2003.

PRESIDING MEMBER GEESMAN: And, you know, reflecting on the quality of some of that data, how far out do you think this particular methodology would yield reliable results?

MS. SHEFFRIN: You know, I don't think it's a question of the methodology; it's a question of the data. And I think the power of the methodology is it lets you evaluate what impact, you know, a lot of uncertainty on variables makes.

So, I think that's, in fact, the strength of the methodology.

PRESIDING MEMBER GEESMAN: Well, okay, I'll turn that around. Recognizing the inherent strength of the methodology, looking at the crummy data that --

MS. SHEFFRIN: But, you know, you can decide, as a decisionmaker, what's crummy. You don't trust the load forecast; you don't trust gas prices. You can run the scenarios and see what the impact is and see if it would change your answer.

PRESIDING MEMBER GEESMAN: But I'm not certain that's very satisfying. I'm wondering, you, yourself, said we're dealing with long-lived investments here. I'm wondering how much value to attach to even the best methodology ever concocted by man if inherent data limitations prevent me from fully capturing the stream of benefits, and perhaps the stream of costs during the full period of that investment.

MS. SHEFFRIN: Sure. I agree, you know. Would I put my life on the benefits are going to be exactly this? Absolutely not. But, you know, do we come in the ballpark or not? Are you saying that we still may be underestimating the benefits?

PRESIDING MEMBER GEESMAN: I'm saying in a very severe fashion you may still be. If, in fact, and I've actually been quite taken by the way she put it several workshops ago, but if Patricia Arons has it right, and these are societal choices, we're dealing with, I think, as long-termed or long-lived an investment as the public sector ever is called upon to make.

I'm extremely wary of techniques or methodologies that are inherently data constrained, that don't capture that full stream of both costs and benefits during the life of the investment.

MS. SHEFFRIN: I guess what we're saying is the methodology, itself, doesn't prevent you. You can put in as many dozen what-if scenarios that you think can capture that future. But, at least it's a, you know, a well documented way of studying what those impacts are.

You can say, well, I don't believe any of this, and I'm going to make my decision on something else. You can do that.

PRESIDING MEMBER GEESMAN: That'll get you in trouble at the PUC.

MS. SHEFFRIN: Well, I think it would get me in trouble before the CEC. I think when people are asked to make a recommendation they're asked to define how they came upon this recommendation. I believe this methodology gives some way to defend how you came upon it.

I agree, it's based on, you know, data that you're very uncertain about. But, that shouldn't stop you from, you know, putting in, doubling the load forecast, you know, putting in whatever extremes you think are possible.

As you can see from the extreme of the examples we came up with, we came up with a huge range of annual benefits, all the way from a negative 5 million all the way to $30 million a year. So I think we are trying to approach capturing some of those, quote, "nonquantifiable" benefits and making them quantifiable to the extent possible.

In the end it is always an issue of, you know, gut level what do you feel. But I think we're trying to put a lot more than just gut level behind the decisionmaking.

PRESIDING MEMBER GEESMAN: But if I recall the slide in front of this one accurately, market price and gas price are extremely sensitive variables. And those have demonstrated extraordinary volatility over the last several years.

MS. SHEFFRIN: And that's what we have done. When we took the low gas scenario and the high gas scenario, the way we calculated is we went back, and fortunately from the CEC we have 20 years of your predictions, and so we calculated the standard error and the average based on all of that.

So we looked at the past 20 years and said, how wrong were we, and can we use that to inform ourselves.

PRESIDING MEMBER GEESMAN: So, I've got a 50-year societal choice to make; I've got an extraordinarily precise and well calibrated model. But I'm driven by extremely volatile --

MS. SHEFFRIN: Inputs.

PRESIDING MEMBER GEESMAN: -- assumptions.

MS. SHEFFRIN: Right. Right. But this gives --

PRESIDING MEMBER GEESMAN: And yet Armie tells me that there are no white elephant transmission projects. There are no stranded asset transmission projects.

MS. SHEFFRIN: Right, but what we've tried to do is improve on Armie's gut level feeling, and try to put it down in, you know, black and white.

PRESIDING MEMBER GEESMAN: That may have been a mis-investment.

(Laughter.)

PRESIDING MEMBER GEESMAN: I'm troubled that in fact we've all been lured into a bean-counting exercise that, in fact, doesn't yield results anywhere nearly as precisely as it purports to, and yet which still systematically undercounts benefits. And fails to accurately take into consideration the timeframe of the societal choices that we're being asked to make.

MS. SHEFFRIN: Yeah, you know, I would definitely agree with you. Transmission investment is like every other public investment and every other public good, it always is fraught by two concerns. One is tremendous under-investment, because we're all required to pay for it and we all benefit regardless of whether we pay or not. And the second is once it's built it tends to be over-utilized.

So, I think transmission investment is no different than any other public good investment decision.

PRESIDING MEMBER GEESMAN: Well, I thank you for your presentation, and I certainly recognize the hard work that's gone into bringing this up to where it is now.

MS. SHEFFRIN: Thank you. And I'm going to let Mingxia just go over one of the key issues that I think we've provided value added, and that is the impact of market pricing.

MS. ZHANG: Good afternoon, everyone. My name is Mingxia Zhang; I'm a principal economist working at California ISO market analysis.

My presentation today is to focus on the market-based simulation of our TEAM methodology and also our application to the Path 26 study.

Anjali already discussed we have five key principles of the TEAM methodology. And one of the key principles is how we're going to model generation bidding behavior in the wholesale market regime. And traditionally all the models are -- use under assumption of cost-based bidding.

But our historical evidence has indicated that the generators might bid above their marginal cost. And I think of people in this room are more familiar with that than I am because, you know, I was new to the industry.

But more importantly, transmission

expansion can enhance market competitiveness and our methodology should be able to capture this benefit.

Our goal is to perform transmission evaluation based on market prices rather than traditionally cost-based analysis. And more specifically, we needed to model suppliers' strategic bidding behavior and how their bidding behavior might change with transmission upgrade.

Modeling strategic bidding is a very difficult task. A lot of -- in the past several years a lot of academics and also predictioners are working very hard trying to work out some (inaudible) approach. They have tried a Cournot type models, supply function caliber models. But those models are very difficult to implement in the complex network representation of the transmission grid. Those models usually are conducted only for, you know, where's simplified network, six busses or eight busses.

Another alternative approach is empirical approach which is to use a historical evidence or historical experience between what we observe in the market, price-cost markup, and system conditions. And in this methodology and

Path 26 application we estimate a historical, a statistical relationship for California.

And we apply this historical relationship to California. This can be easily done to a zonal configuration of the network model. And it can also be applied with calibration to nodal network.

As I already said, we tried to develop a historical relationship between price-cost markup and a certain system conditions. And then we use the price-cost markup to predict bid-cost markups for generators, and future system conditions. And then we applied bid-cost markups to the system to supply bids to all generators bids, and rerun our network model to determine economy dispatch and market clearing prices.

And -- okay, historical price-cost markups are based on the differences between actual zonal market prices and what we estimate the competitive benchmark. And then we used the bid-cost markups prospectively in our transmission study.

The bid-cost markup reflect difference between the variable cost of a generating unit and a market-based bid.

This is kind of in detail the description of what we conducted for Path 26 study. We estimated relationship between price-cost markup and system conditions using hourly data covering November 1999 up to 2000, and the whole year of 2003. And also the price-cost markup is expressed as Lerner index, which is the difference between zonal market price and the competitive benchmark over zonal market price. And for each hour and for each region.

Here we have two major important regions in California ISO area as P-15 and MP-15. And the system conditions are represented by several key market variables, such as RSI and also percentage of un-hedged load.

And on this slide I want to go through briefly residual supply index RSI. The definition of RSI is how pivotal a large supplier in the market to meet the zonal demand. So the RSI, the numerator is the difference between total supply and the largest supplier's supply. And the numerator is the total demand.

The RSI theoretically value less than 1 indicates the largest supplier is very pivotal in meeting demand.

In our ISO markets, our historical experience indicated that usually RSI value less than 1.2 have generally been associated with market price in excess of estimated competitive benchmarks.

RSI captured the impact of transmission upgrade on supply/demand balances. Here, in the total supply, total supply includes import capability to importing region. So if you have upgrade then you have an upgrade of a major inter-regional -- then your total supply increases. And then your RSI will be different for that hour and for that region, holding all other system conditions the same. Your upgrade will change your RSI value.

This is just to show our regression results. We tried different functional forms, we tried different combination of variables. And I won't to go through to the details to the results, but this shows our effort, almost our past two years, our statistical work on this area.

Internal supply, this price-cost markup, we apply regression results prospectively to predict hourly price-cost markup in years 2008 and 2013. We used price-cost markup as bid-cost markup with some calibrations. And we estimate price-cost markup for the three major utility regions in the ISO area, PG&E, Edison and San Diego.

And because our regression is not -- has not -- does not have a perfect fit to predict historical price-cost markup, so we proposed, we used a different, three different levels of price-cost markups, the base, and the high and the low. This chart shows what we tried to capture the sensitivities and the variations in bid-cost our markups. Instead of just using directly what we predicted from the regression model, we tried to expand the range of the bid-cost markups. And tried to capture a wider variation in this variable.

This bid-cost markup functionality is incorporated directly into our PLEXOS model, which is the production cost, the cost of production simulation that we adopted for demonstrating our methodology in the Path 26 study.

All the variable are (inaudible) and other variables can be internally computed in our PLEXOS model. And also the project the bid-cost markups can be automatically added into generations marginal -- on top of marginal cost. And also all the benefits, the strategic benefits from modeling market prices are calculated internally in PLEXOS model.

Although we spent a lot of effort on this approach, we do realize that we, you know, there could be potential of future enhancements to this approach. Specifically remember what we did is to apply a bid-cost markup as -- I'm sorry, use the price-cost markup as bid-cost markup. And we could, you know, develop another regression to just the focus on generators bid-cost markup, although that approach is more complicated and is going to be more difficult because we're not talking about the market, we're talking about a larger suppliers and their portfolios. But that's something maybe we need more further research and development. Also, for the future we're going to keep exploring the game theoretical approaches.

Here is just a slide showing the difference between a cost-basis simulation and market-based simulation. This is for year 2008. Path 26 case study and holding all the system conditions at a base. That means we use CEC's basecase load forecast and we assume future gas prices are at base. We do not, you know, those are kind of moderate conditions to the market.

And then you can see a difference between the cost-based benefit and the market-based benefit. And if you look at the whole WECC region, the total societal benefit, which is the production cost saving in the whole WECC area, the cost-based simulation only gives you about $1 million benefit in year 2008. But the market-based simulation gives you $4.28 million.

And the rest showing different perspectives of our methodology. And for the ISO ratepayers, the market-based simulation can give you $19 million, which is very very high. I mean much higher compared to cost-based simulation.

That concludes my presentation. And I would like to take any questions.

PRESIDING MEMBER GEESMAN: When you were developing your historical relationships between price-cost markups and certain market conditions, what period of time do you look at in terms of California's market experiences?

MS. ZHANG: We look at November 1999 to October 2000; and also year 2003. Those are pre-energy crisis and after.

PRESIDING MEMBER GEESMAN: And do the two periods reflect a similar experience, or were they both --

MS. ZHANG: The two periods, I would say they were different, but the reason we want to incorporate the two, both periods is because in our modeling we tried to incorporate the impact now for state long-term contract. And the first period did not have that factored in. So we needed to have a period to have the state long-term contract in effective.

PRESIDING MEMBER GEESMAN: So do you feel that basing your empirical approach on those two periods fully captures the range of possible market conditions that California will face during the study period when you expose Path 26 to this analysis?

MS. ZHANG: That's certainly our intention. I mean whether we captured the full range of the market, you know, extreme conditions, that is only part of the study. And on the other hand we tried to simulate a lot of the extreme conditions such as, you know, very very high demand in growth, and also very dry year in the whole WECC region.

And also we conducted simulations for contingency events such as the (inaudible) dc line could be on outage or the SONGS nuclear plant on outage. So those are extreme conditions that we modeled.

PRESIDING MEMBER GEESMAN: And how did you determine bid behavior in those extreme conditions if they didn't occur in 2001 or 2003?

MS. ZHANG: Remember the variables, RSI and others, some condition variables was already captured the market conditions. So if, for example, if SONGS is outage, then the total supply to Edison area will be different than without SONGS going on outage.

So those conditions already captured directly in the variables for each hour and for each region.

PRESIDING MEMBER GEESMAN: Thank you.

MS. ZHANG: Thank you. Any other questions? Thanks.

MR. KONDOLEON: Thanks again to Mingxia and Anjali for coming here today.

The next presentation will be provided by Joe Eto representing CERTS. He will discuss the most recently received report prepared by the

Electric Power Group for the Commission. And it's the third in a series of reports on strategic benefits. You've heard from Joe before on the previous two reports, and he'll discuss the third one here today.

MR. ETO: Thank you very much. My name is Joseph Eto; I'm a Staff Scientist with the Lawrence Berkeley National Laboratory. And I manage the Consortium for Electric Reliability Technology Solutions. We are an industry university national laboratory collaborative that is working on public interest electricity reliability technology development both for the Department of Energy's transmission reliability program and for the California Energy Commission's PIER program.

Most of our work is focused on development of real-time operating tools that are being demonstrated today at the California ISO through cooperative arrangements between the Department of Energy and the California Energy Commission.

We've also been tapped to support the Department of Energy number of policy-related activities including the national transmission grid study and also technical support most recently for the blackout investigation of August 14th.

As part of the IEPR process this year we were invited by the Commission to prepare a series of white papers on such transmission planning topics. These were led by my colleague Fred Mobasheri of the Electric Power Group. And I'm pleased to have the opportunity to present his work to you today.

I want to briefly review the first two products, the first set of contents that I'll be talking about today. The first part that we prepared was a review of California's historic transmission investments to try to identify the number of benefits, the large number of benefits that those investments have had for the state and for the west, as a whole; many of which were unanticipated during the planning process. And that really was a context-setting discussion for thinking about how we look at transmission planning going into the future.

The second report that we prepared which I presented earlier this year was a scenario study; a very long-term scenario study looking 30 years out to the future, looking at a strategic approach toward thinking about transmission planning. No complicated models involved; just very simple spreadsheet exercises. The type of planning that we hope the Commission will consider as it thinks about the longer term strategic decision it needs to make about transmission planning going forward.

In this paper, which is out on the front desk, we take a broad view of looking at some of the economic considerations that need to be considered in a transmission planning setting.

We're very fortunate in that the timing was such that it falls very closely on the heels of the pioneering work that the California ISO has just filed and that we just heard about. So many of my comments will speak to aspects of that analysis. But also other considerations that we think are important for transmission planning.

And finally, we are preparing this report as contractors of the Commission. I want to really emphasize that the comments and opinions I offer in the next few minutes really are those of the authors and of myself, not necessarily that of the Commission.

I think it is important here, you know, we've had very technical discussions up until now on a number of very detailed aspects of transmission. I think it's important to go back to where we started and setting a broader context for some of the transmission planning evaluation recommendations that we have.

Why do we build transmission? There have been a number of reasons. The earliest historic justification was to connect remote power plants that were deemed appropriate for the resource mix to the load centers. As power plants got located further away, we needed to bring the generation to the load.

Interconnect arose as a way to increase the reliability of the network; as a way of sharing reserves among utilities in a more cost effective manner than having stand-alone systems.

As regional surpluses and regional resources became more developed, transmission became a way to access market hubs for surplus capacity and energy.

And ultimately now we have a system that's able to take advantage of load diversity and increased resource and fuel diversity. And that really is where we're starting from in the transmission expansion planning process.

Transmission is a very unique kind of resource, and that really is at the crux of many of the problems we face in transmission planning today. The resource, itself, is quite capital intensive, not as capital intensive as generation necessarily. But is a resource in which all the costs are essentially upfront. The costs of operating these assets are very minimal compared to the cost of building them.

In addition there are significant economies of scale with building transmission, such that additional added costs upfront can be very low for great increases in capacity. Again, this speaks to the optionality or the lack of optionality that some of the transmission investments have, and why it's sometimes hard to consider that in the planning process.

Another critical complication is the very long lead times involved in planning, permitting, designing and building transmission. Complicated with that is the very long physical life. We've spoken many times today about the very long-lived nature of these assets. So you have large, lumpy assets that are expensive to build initially, which have very long impacts. And at the same time, planning processes that are not necessarily well suited to that, and which we are now starting to adapt to try to begin to take advantage of those.

I think it's critical, and again this goes back to the first of the reports that we prepared for the Commission, to recognize that despite, or in fact in view of these specific attributes of these resources, they have strategic values that are quite unique to them. The access to other resources; the reliability benefits; and essentially the insurance against contingencies.

These values have been critical dimensions of the value that transmission has provided to California and to the west, and values that we think are very important to consider in any planning process.

And so I would say in a nutshell our goal here, thinking about transmission, is to insure that we can capture all the benefits, as well as cost, in order to make better decisions. And I think we will talk a little bit more about the aspects of which some of these benefits and some of these decisions really have the characteristic of public goods decisions. And we begin thinking more explicitly in those terms as we start making those decisions.

Let me start by talking about what we need next by talking about where we've been again in terms of how planning has traditionally been done. The historic approach to transmission planning has been multi-area production cost simulation tools in which we essentially assume that generators can operate at their marginal cost.

This, again, stems from the vertically integrated historic nature when the industry was organized. It reflects a lot of informal data sharing that takes place among many parties. And really fundamentally represents a situation where market considerations are a very minimal aspect of the planning and operating decision.

And so a little feedback between the transmission expansion and power plant construction, they're essentially jointly optimized in that vertically integrated setting.

Regional and marginal costs are essentially equated to marginal prices. The benefits of imports are basically based on the difference in the marginal costs between importing and exporting regions.

And there are a number of standard sensitivities that you can conduct, and which have been appropriately conducted in the past regarding fuel prices, load forecasts, hydro production and other factors.

That's where we've been. That's where the tool sets that we are largely working with were developed and what they were designed to support.

Let's talk about what's changed now. I think this came up in our panel discussion earlier. There are a lot more players now. We have unbundled generation and transmission. I don't think that is a genie that we can put back into the box. And we need to accept that we need processes that recognize the very great number and diversity of the kinds of viewpoints that need to be brought together into these transmission planning discussions.

The location of new generation at this point, based on the rules governing interconnection, tend to create congestion. There is really not an incentive for generation to locate in a place where it lowers systems costs overall, but really minimizes the interconnection costs to the developer.

Market prices, as we've just heard from a very extensive technical discussion, don't reflect the cost of production. Bidding has a very critical impact on the way in which transmission is used these days, and the way in which prices result. And so there's a lot of need to take into account these bidding strategies, the role of market power, where new entry will take place, and what type. And so a whole host of uncertainties that we've historically not dealt with, and which quite frankly we have modeling tools that are not well suited for, because they really didn't consider them in the way they were initially conceptualized.

So this is really the challenges that face transmission planning today; ones which I think, from my perspective, that the California Independent System Operator has done a good job of beginning to address. I mean I would like to step back, and then I will make some comments about areas to enhance the modeling activity. But this really is path-breaking work. I've looked at a lot of transmission planning activities across the country, and the depth and the comprehensiveness of some of the issues that are being treated here is literally path-breaking around the country.

And so these are all appropriate, important first steps. I think this issue of modeling market power much more explicitly is essential. It's the reality of the world in which transmission will be serving as we go forward.

I think that we've spent a lot of time talking about uncertainty; I'll talk more about uncertainty. So this idea of looking at scenario analysis as an approach to begin framing and dimensioning the uncertainties we face absolutely critical, and a substantial improvement over the types of approaches we've taken in the past.

I think again from the technical side, choosing an appropriate tool, one that actually can represent the realities of how power flows in an electrical network is critical to being able to realistically represent what is and what is not do-able with the transmission system.

And I think finally really the idea of beginning to take into account the many perspectives that are affected by transmission decisions is critical toward informing the public discussion and debate that needs to take place about who are the winners, who are the losers, how can they be compensated, and how can we move forward and something that will represent a more consensus decision that we can all agree upon in terms of what types of transmission may be appropriate and where it might be located.

I'm not going to repeat this. I think, you know, how could I do a better job than Anjali and Mingxia Zhang telling us about what they've done.

I guess what I want to say about the economic evaluation of Path 26 is that it represents an application of the methodology that they have developed. It does not exploit its full capability in terms of what it is capable of doing. So many of my comments are going to speak to sort of what is, in principle, possible, and what is, in fact, done.

And some of the suggestions that we have go to trying to improve the implementation in future studies. Not really questioning at this point some of the specific functionality that exists within the model, which we do think is appropriate and necessary for making these kinds of evaluations.

So I think the things that I want to focus on really are the choice of two analysis years; the way in which some of the levelization is done in terms of expressing the benefits, and the way in which some of the things are and are not able to be captured when you take this kind of structure and try to make an application of this methodology.

And so let me elaborate on that in the remainder of my slides. What I want to start with is reviewing what we consider to be the strategic values of transmission; and then assessing the extent to which the model or its application begin to address those.

I think price stability is a critical concern in transmission planning, and one which I think we're barely beginning to scratch the surface on. I think some of the scenario analysis begins to touch on that, but I think that none of the modeling approaches that I've seen really do address the day-to-day volatility in market prices that we actually do see in today's markets.

There's a smoothing effect that necessarily takes place in the way in which modeling can take place.

Yet that volatility is critical to the economics of many of the new generators' decisions, and should be accounted for in the kinds of planning decisions that we make with transmission.

Transmission planning clearly decreases the market -- the addition of transmission clearly decreases the market power (inaudible). I think the methodology has made a good start on that. Clearly there's a tremendous gap between the theory that's been talked about, about how to address these issues, and what has been practical and implementable in the time the ISO's worked with. But the fact that this has been recognized and made a foundation piece of that methodology, I think, is quite valuable.

The third issue, the issue for potential for increased reserve showing firm capacity purchases, I think here's a situation we've just started to scratch the surface. There's a lot of discussion about how the contract requirements will be carried out. There's a lot of discussion about how the reserve margins are being implemented.

Here's another area where I think that transmission does allow for reserve sharing; it does allow for firm capacity purchases offsystem to firm up some of your resource needs. That interaction, I think, could be strengthened and improved in assessing where transmission -- what the kind of benefits that transmission does bring to the system.

And area where I think probably not too much -- no one can do too little in this area -- is this issue of insurance against the abnormal system conditions. I think time and time that we've heard from Armie this morning, and from many others, that having transmission gives you an optionality, an opportunity to access things that you might not have already planned for.

And I think looking at some extreme scenarios is quite appropriate in that vein. But I think it's just the tip of the iceberg, and that we need to be much more explicit about the role that transmission plays in providing insurance against abnormal contingencies. What are the costs of those contingencies to us as a society. What is it worth to pay for the insurance to try to avoid them. I think we're beginning to scratch the surface in that area; I think a lot more work can be done.

Environmental benefits, clearly access to remote resources, the opportunity to bring clean resources in, to back off on more dirty resources closer to the load centers where human populations live. It's a clear benefit for transmission. One that I think the model is capable of addressing, but it's not been exercised in the current context. I would encourage more work in that context.

Ripple effects from transmission are another area that I think deserving of more study. And this, again, really goes to some of the limitations of the kind of timeframe that you can consider in the exercise that we've been presented with.

You know, if we look at a future that has lots of gas generation then we have to start looking at a future that has lots more gas pipelines. And how do those considerations trade into the transmission planning decision.

You know, again we're starting to assess what that might mean for gas pipeline construction, but we're not really integrating that into our thinking process as we think about trading off transmission.

And finally, and this is the issue that I'll talk quite a bit about, or not a lot, but spend some time talking about, are that the benefits accrue over a very long period of time from transmission. These are assets that are going to live 30, 50 years or more.

And we need to make sure that we don't unfairly treat the benefits that come from long-lived assets in making the tradeoff between these long-lived assets and assets that may have a shorter lifetime.

So we have some specific suggestions for areas for the Cal-ISO to consider in enhancing their methodology in future iterations. One, we think that it is important to capture the dynamic impact. The feedback that goes on between putting in a line, the changing in market prices in the remote areas, as well as in the local areas, the impact that has on future generation build decisions.

And that there's a dynamic there that I think we're suppressing to some extent. I think there's an effort to try to capture some of that in their current methodology, but it is suppressed when you only look at essentially two test years and try to extrapolate from them.

We think that there's an opportunity to capture more of the potential for firm capacity from exporting regions as part of the resource adequacy requirements. And that that needs to be teased out a little bit further. I think there's openings for that, but I think that that would really have an important effect that we should consider when we look at transmission lines.

I've already mentioned environmental benefits. I think again here's a safe -- where there's a capability of functionality. I think it should be exercised in the future.

And then finally I've also mentioned this reduction in construction of additional infrastructures. Here again this really speaks to some of the issues that need to go outside what is possible to expect in the CAISO methodology. It really speaks to the long-range strategic planning activities that I think we, as a state, need to take on more forcefully as a whole.

I want to spend a little time on this

one specific issue. It's come up a couple of times in today's discussions in which I think in view of a number of the features of transmission, it is very appropriate to begin thinking of it in the context of a public or as a public good much more explicitly than we have done so in the past.

And I'll describe my rationale for that and then tell you what I think that means from the planning perspective. The planning, itself, is shared among multiple stakeholders. The ISO controls the operation of the lines. Many of the customers of the utilities owning the lines don't receive the benefits of the lines.

The benefits, themselves, and this is the key actually to the public good cannot be denied to any retail customer, nor to any generation or transmission owner regardless of who carries out the expansion. Again, this goes to the network nature of electricity flowing where the laws of physics dictate that it will flow.

The capital cost is paid by one set of customers. They may not be the sole beneficiaries. And I think, you know, the problems that transmission causes or inadequate transmission causes in terms of congestion, in terms of exacerbating opportunity for the exercise of market power, and the reliability problems that it can create are ones that are borne by the public at large.

And so this, we submit, leads us to believe that, you know, it's not just a matter of thinking in terms of what is a right range of discount rates, but the exact choice of the discount rate that we need to think about in evaluating the future transmission investments. And that we think that in view of the public goods nature of transmission, it is appropriate to consider something closer to the social discount rate rather than utility costs of capital. I'm going to speak to that very specifically.

So I think again the ISO has made a step toward this. There is certainly an opinion from the MSC to begin looking at a range of discount rates in view of the multiple perspectives that are affected. Here I'm suggesting a special consideration be given to the discount rate that might be more appropriate of a social or public good.

So, specifically there is a large literature about public goods and the appropriateness of using social discount rates. There's a lot of detailed academic discussions about what that should be.

But I think the bottomline is it's really a lower discount rate than we're used to seeing in utility opportunity cost of capital kinds of calculations. And that the studies that we've looked at suggest that the appropriate social discount rate for the U.S. is around 5 percent.

And I'll give you a demonstration on the following slide of what a major impact this can have in terms of switching from a 10 percent discount rate to a 5 percent discount rate.

We believe this is critical for capturing the benefits appropriately that come from transmission projects. But we recognize, in terms of the actual ratemaking procedure, in terms of determining transmission access charge, of course we should continue to use the utility opportunity cost of capital as we've done traditionally.

This is an example, a very hypothetical example of a transmission expansion project in where we make some postulates about what the margin, or the price difference that we could achieve and capture to different degrees of line loadings, based on the assumption of discount rate.

When we look at under a 10 percent discount rate, net benefits of a 30-year lifetime of about $500 million. But if we go to a lower discount rate, a social discount rate, those benefits increase by about 50 percent, more than 50 percent, to $867 million.

So, again, this will have a measurable effect on calculation of the benefits that would come from a transmission expansion project. And why I think it's a very serious issue for folks to consider going forward.

I want to step; back now from the specific comments on the CAISO methodology to talk about how we see that methodology fitting into some of the larger transmission planning kinds of decisions that we think need to be made.

In the second report that we prepared for the Commission we talked about a long-range scenario exercise that looked 20, 30 years into the future. And we suggested that transmission planning ought to be thought of in at least two phases. And I think we've heard this from speakers earlier today.

Essentially a first planning or long-term strategic phase that would be focused on building consensus on the need for lines. Identifying at the very broadest level potential projects. But specifically to initiate and enable corridor planning and right-of-way acquisition long in advance of the articulation of very specific projects.

And that this would be distinct from the permitting phase, which would have a much narrower window of looking five to ten years out at very particular, specific projects that may be proposed. And which a much more involved economic justification using a more detailed evaluation methodology such as the one the CAISO has developed would be appropriate.

And this goes a little bit to the interchange that the Commission was having with Anjali a little bit earlier, in that it's our belief that when you get the right tool for the right job. And I think that methodologically speaking is a wonderful methodology that the CAISO, and I think that we should be very pleased that they have pushed the state of the art in that way.

But I think the data issues and some of the issues that we need to address on a proactive basis from a strategic standpoint are ones where we'll get lost in some of these trees discussions. And we need to step back and look at the forest, and not confuse the things that we can count for the things that really count, and that are needed in order to move transmission planning forward on a longer term basis.

Why we believe this is appropriate is because we believe that a critical next step, a critical missing ingredient today is advanced acquisition of right-of-ways and corridor planning. An idea to try to get on some optionality in land use planning today that allows us to develop in a more orderly fashion a transmission network that will serve everyone's needs. And not find out after it's too late and suffer the consequences of not having that advanced planning.

So we're recommending a process by which advanced acquisition of right-of-ways takes place. Again the justification here, it's difficult to get siting approval. And we think that it is needed to get the utilities back into this program of site banking in anticipation of future need.

And I know that we're going to have some information in this workshop that that's available to talk about, about how that's treated at the PUC.

But again, we believe for the purposes of that type of assessment, simple analysis may be appropriate in recognition of the longer range strategic nature of the kinds of decisions that need to be influenced. And the need to sort of be cognizant of the kinds of uncertainties that we're dealing with in terms of the data that we might use to support some of those decisions.

So, to summarize, we have a number of specific recommendations. We believe that it's very important to take into explicit account the dynamic interaction between transmission and generation expansion. This would involve more years of simulation, rather than the two test year approach.

We believe that it is appropriate to capture the long-term benefits of transmission lines by extrapolating some of the analyses out to the end point of some of the lifetimes of these projects.

We believe it's appropriate to look at the value of firm capacity that might be accessible through the transmission lines that would be constructed.

We think it's very important to include the environmental benefits associated with transmission expansion.

And importantly, we think that to make decisions about public good such as transmission it's appropriate to use a social discount rate to calculate the present worth of benefits.

That concludes my prepared remarks. Let me open it up to questions now. First from the Commissioners.

PRESIDING MEMBER GEESMAN: I'd simply observe that the Energy Commission, in its building standards and appliance efficiency standards, utilizes a social discount rate. And I'm not certain that the same logic doesn't apply right here. If I'm wrong in that I hope at some point in time people will correct me.

But I think you've done a real service, Joe, in framing the issues this way, and thank you for your presentation.

MR. ETO: Thank you. Other questions? Sir.

MR. GILFOY: I'm Chuck Gilroy with TransAlta Energy Marketing. And I don't necessarily disagree with the concept behind the social discount rate. But to me, doing that seems somewhat arbitrary. Because aren't you really trying to, in applying a social discount rate, aren't you really trying to derive some actual dollar figure that assigns a value to the public good that you created.

And so it almost seems like why are you -- it seems arbitrary to use a social discount rate as opposed to just apply, say for example, on the benefits side of the equation a dollar figure that you can actually justify, or at least attempt to justify, such that your net present value figure that you come up with is the same. Whether you use a 10 percent on -- using 10 percent or, in your example, 10 versus 5 percent.

So what is the point of the social discount rate methodology, as opposed to, like I say, just assigning an incremental benefit so that you would come up in your example with the $867 million?

MR. ETO: I'm not sure I'm understanding your question correctly, but let me try. I want to distinguish between the ratemaking application of these kinds of analyses and where it is appropriate to use a utility cost of capital from I believe the more global and societal perspective in assessing the benefits from these types of projects.

And, again, I want to go to the public goods nature of the investment, itself; the multiple parties that are affected by the transmission investment, both those who would pay the access charge within California and those in the region. Those who benefit from the externalities that are created by transmission in terms of the insurance against contingencies.

The environmental benefits that are thereby created. And really put it on a level playing field with other public goods and infrastructure investments that we're considering as a society. That's really the basic rationale that we're using here.

MR. GILFOY: We'll talk offline.

MR. ETO: Other comments or questions?

All right, thank you very much.

MR. KONDOLEON: Thank you, Joe. The final presentation will be a staff update on the southern California transmission corridor study process. And that's going to be provided by Kristy Chew.

MS. CHEW: Thanks, Don. Good afternoon; my name, again, is Kristy Chew, Project Manager here at the Energy Commission. And I'm working on the transmission corridor study proposal that we proposed back in earlier this year, but we specifically highlighted it at the May 10th workshop.

And today I'll be sharing with you comments that we've received to date. They're all by mail, and so far we've received some comments. And I wanted to go over those in summary with you all today.

Background. The Energy Commission had requested information from various utilities, mainly in the southern California area, because that's where we're focusing this study, or that's where we're proposing to focus this study this year for the 2004 IEPR update.

And we also sent individual letters to

utilities and we asked for comments and suggestions from everybody present at the last workshop to comment on the study and the proposed contents of that study.

We've been pretty pleased with the comments that we've received so far. We have comments from Los Angeles Department of Water and Power, Mammoth Pacific, San Diego Gas and Electric and Southern California Edison. We're still hoping to receive comments from Imperial Irrigation District and Pacific Gas and Electric.

To summarize Mammoth Pacific's comments, as Judy Grau mentioned earlier, they indicated in their comment letter that Path 60 has two constrained lines, lines 30 and 31 between the Bishop substation and Inyo/Kern substation. That those two lines significantly impede distribution of resources from the Mono/Long Valley known geothermal resource area.

They stated that if there were improvements to those lines they could increase generation from 40 megawatts to 150 megawatts or more. They asked that the Energy Commission recognize Path 60 as a priority corridor for study.

Going on to comments from LADWP. They suggested that the study identify land corridors that may be reserved for future transmission construction. They recommended potential upgrades to existing facilities to increase transfer capability. Include considerations for expected in- and out-of-state resource locations, Mexico, Arizona and other instate resources such as the Salton Sea geothermal area or Tehachapi.

Feasibility of maintaining the corridor for future use. Planned utilization of existing facilities; upgrade potential of existing facilities; and considerations for future demand distribution in the state.

Going on to San Diego Gas and Electric comments. They identified that the study should talk about expansion needs to insure access to the optimum mix of long-term energy resources in California. Including renewable resources and energy imports from outside the state. They stated that the state's energy policy must include a process to designate appropriately sited utility planning corridors across state- and federal-owned land such as Anza Barrego Desert State Park, and the Cleveland National Forest.

And they suggested that if we did that there could be additional access to out-of-state power renewable resources within the state. They also indicated that the study should outline how this process aligns with the ISO and the grid planning process. And also how it fits in with the PUC's licensing requirements.

They thought that the Energy Commission and the PUC should work together to identify steps needed for the timely, efficient construction of future transmission infrastructure. They suggested that joint efforts should consider whole system integration, including an engineering system analysis of the grid to determine how much wind generation can be connected in a single wind regime without creating operability problems.

Going on to Southern California Edison's comments. They submitted the most extensive comments, and they grouped it into two different groups. One, they recommended what should be included in the study; and then an actual process of how to go about doing what they're recommending.

So, they have the first six steps. Should be, one, the corridor study should identify transmission corridors for future needs consistent with the provisions of general order 131D.

The study should also focus on identifying viable transmission options in which a) projects can be constructed; b) sensitivities that can be mitigated; and c) system reliability that can be maintained.

Their third step in the process would be at the conclusion of the study the viable options would be adopted as corridors by the Energy Commission.

Four, the state could then initiate a programmatic EIR, the development of a statewide mitigation plan, and coordination with local jurisdiction to include the adopted corridors within local general plans.

Five, initially the study should focus on the southern California region and lines necessary for the interconnection of renewable generation resources.

And lastly, six, lessons learned would then be applied to the study of other geographic regions such as northern California, and other types of needs such as service to load and imports.

Their recommended study process would be to first establish protocols, rules and principles for corridor evaluation. For example, corridors should avoid common contingencies or avoid cultural and environmental sensitivities for assessing the viability of transmission options.

The second step of their process would be to define corridor widths considering widths that are appropriate for a program EIR and also width that is sufficient to prevent creating new reliability problems from common contingencies.

So they're suggesting that we look at two different widths in our study; one that would be supportable by -- for EIR, the environmental process. And also from a reliability perspective, how far a distance it needs to be studied and or adopted.

PRESIDING MEMBER GEESMAN: Well, do you see that as studying two separate widths. Is that not the same as one width that would satisfy both purposes?

MS. CHEW: I see it as one width that we could use for both. However, I would need to speak to SCE to ask them more specifically --

PRESIDING MEMBER GEESMAN: Yeah.

MS. CHEW: -- what their intention was. But, I guess there could be some offsite impacts from a CEQA standpoint that might need to be considered as well.

PRESIDING MEMBER GEESMAN: Well, I guess where I'm not clear is what limitations would there be on a programmatic EIR in terms of corridor widths that we study. Obviously you need to have some limits. I'm simply not clear on what they would be.

MS. CHEW: No, and staff doesn't have a clear indication of that, either. And we hope to talk to the Committee about that and develop that; and decide what we should do for 2004 and what we should do for 2005.

PRESIDING MEMBER GEESMAN: I think you should loop in our general counsel's office.

MS. CHEW: Oh, yes.

Okay, the third step in SCE's recommended process would be to plot the sensitivities, cultural, environmental, visual using all available data sources. Corridor -- to be both consistent with the identified need and within the defined protocols would be adopted is what they're suggesting.

And fourth, once that these corridors are adopted and incorporated into official database, then the Energy Commission could then take steps to develop a programmatic EIR; to develop a programmatic mitigation plan for the state. And coordinate with local jurisdictions and agencies to develop this process for other parts of California.

They also included a diagram of how they thought the process could proceed. So you can see the first box, the transmission line concept. Those ideas would be submitted to us from the utilities.

And then the Energy Commission, in the second box, would provide a sort of assessment of those corridors and transmission lines. We would develop protocols, define the width of the corridor and plot the sensitivities surrounding those transmission lines and corridors.

And then lastly we would adopt the corridors and support them and get agreement or try and get agreement with local agencies.

And then the last steps would be to provide and prepare a programmatic EIR with mitigation and coordination.

What staff intends to do now with the information that we've received to date is to meet with the Committee; discuss with them and make suggestions on what we can accomplish in 2004, and what we should or try to accomplish in 2005.

This is an ongoing process and we don't know how much we can get accomplished in 2004, since the reports need to be generated during the summer so they can be adopted in the fall. But we hope to lay out the groundwork for that and present to people what we think will -- what should be done and how we will go about doing that.

And lastly, we're still hoping to get information from PG&E and the Imperial Irrigation District. So we're hoping to get information from them. And if you have any suggestions that we -- haven't already been captured by the other commenters, to please go ahead and submit those.

And if there's any other comments that people see or concerns that they see with some of the suggestions that have been presented, if you would like to share those with us, so we can consider those when we're developing this study, that would be much appreciated. And if we can get those comments by June 25th, that would help us out.

That pretty much concludes the summary of comments that we've received to date on this study. And I will be working with the Committee on developing the next steps for 2004 and 2005.

MR. KONDOLEON: Thanks, Kristy. Yes, Pat?

MS. ARONS: Can I make a comment before we --

MR. KONDOLEON: Yes.

MS. ARONS: I'm Pat Arons, Southern California Edison. The first comment that I wanted to make really went toward your question, Commissioner Geesman, related to how wide of a corridor should we look at.

And you have the right instinct in involving the Commission's general counsel in evaluating it because if you do a careful reading of GO 131D, there's language in there that talks about a corridor that's sufficiently described an then avoid further permit applications.

And I think there's a real opportunity within the existing law for the Commission to make some headway in terms of corridor planning, and really what it can mean for the long term.

I think the other comment that I would make goes to the study proposal number five. It was on page 9. Initially the study should focus on the southern California region and lines necessary for the interconnection of renewable generation.

Actually my thought there was to take one renewable area and focus on that. And my thought was Tehachapi we'd made a lot of ground, instead of trying to do all of southern California. Focus on renewable and focus on one area in particular, and explore the meaning of corridor planning within that context.

PRESIDING MEMBER GEESMAN: You had mentioned that last time. I think that's a very good suggestion.

MS. ARONS: Yeah. That's all, thank you.

PRESIDING MEMBER GEESMAN: Thank you.

MR. KONDOLEON: Well, we'd like to open it up to any public comment on any of the presentations that you've heard today. Steve.

MR. KELLY: Steven Kelly with IEP. I guess I just have one question, maybe two. To

Southern California Edison, on the steps that they recommended.

I'm a little familiar with transmission siting, not so much planning, but was there anything different in that than what is done if you were to site a transmission project? I mean what are the novel things that are in that, or is it just kind of status quo?

I'm basically trying to get an understanding of what are the things we have to change, if anything, in order to --

PRESIDING MEMBER GEESMAN: The premise is by use of a programmatic EIR you can address some of these issues early on and avoid having everything at issue in the permitting stage, or the final permitting stage of the project.

I think that focusing on the provisions of GO 131D would be constructive under the current law. As you and a lot of other people are aware, this Commission thinks the current law should be changed. If, in fact, it is, then I think that's something else that would need to be addressed.

But in keeping with the theme of corridor planning, which the staff rolled out a couple of workshops ago, if we can segment some of these large 50-year societal choices into smaller more digestible pieces, and get the early ones addressed in a planning process, arguably it can make the permitting stage of the process go more smoothly and with more predictable results.

MR. KELLY: So is the real decision in that context not how to do it, but whether to do it, the programmatic EIR?

PRESIDING MEMBER GEESMAN: No, I don't think -- I think there's a how-to because you need a process that carries out the planning intent of CEQA and adequately balances the priorities expressed in CEQA, which is supportable by the local public that will be most directly affected, as well as the general public of ratepayers that we serve.

And I do think that there are some complicated legal aspects to make certain that subsequent government decisions would be justified in relying on that programmatic EIR without triggering, as we've seen so often in the CPCN process, the need to relitigate everything again and again and again.

MR. KELLY: You know my comments this morning spoke to that, the need for a mechanism to make transparent that decision process. So that sounds like one tool to get there.

PRESIDING MEMBER GEESMAN: Yeah.

MR. KELLY: Thank you.

MR. KONDOLEON: Thank you. Any other comments? Anjali.

MS. SHEFFRIN: I didn't get a chance to mention, I really do think that when we look at transmission planning we need to also look at generation interconnection.

And I think Otay Mesa is a classic example of where the plant gets permitted here, but the issue isn't asked, how is it deliverable to load.

It gets picked in the CPUC procurement process. The issue isn't asked how is it deliverable to load. And then all of a sudden something is being added. And it comes to the ISO and it's not deliverable.

So, I would urge that generation interconnection be looked at as a more comprehensive issue.

PRESIDING MEMBER GEESMAN: I think you're absolutely correct in that. And I think what you see in Otay Mesa is the unintended consequence of the arbitrary division which state government fell into 30 years ago in separating generation from transmission.

And these are expensive consequences to deal with. And I think we've got too many different governmental entities looking at similar questions.

MS. SHEFFRIN: Thank you.

PRESIDING MEMBER GEESMAN: Thank you.

MR. KONDOLEON: Any other comments? Well, before I turn it back to the Committee for final remarks, let me express my sincere appreciation to all of you today for participating not only in this workshop, but going back to the previous three workshops, as far back as November of 2003.

Staff has found the information provided by the various presenters and also the information in the various roundtable discussions to be extremely valuable. And our challenge now is to package this into a white paper in the next few weeks that hopefully will satisfy the requirements of the Committee. And to release that by the end of July.

And it's my understanding that we'll

likely have a public event some time in August to talk about that paper. And there may be some follow-on activities in September and October.

But, again, thank you so much for participating. And let me turn it back over to Commissioner Geesman for any final remarks.

PRESIDING MEMBER GEESMAN: Well, I've said a lot today and I'm not certain that I need to say it again.

Commissioner Boyd?

COMMISSIONER BOYD: I don't want to add too much to that. I think this has been extremely helpful and I like the fact that so many people recognize the interfaces and cross-overs that obviously have to be taken into account if we're really going to make a meaningful contribution to this process.

And as far as I'm concerned, bring the 19th century process that I've seen in operation into the 21st century. I mean it's a fast-moving world and we don't have fast-moving processes.

So, I'm encouraged. I commend Commissioner Geesman for all the attention and effort he's put into this. And I rely heavily on him, as well as you, to make a contribution.

So, thank you. And I look forward to our next round of discussions on this.

PRESIDING MEMBER GEESMAN: We'll see you all in August.

(Whereupon, at 3:45 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 22nd day of June, 2004.